I. Meeting Packet

State of Florida

Public Service Commission

INTERNAL AFFAIRS AGENDA

Tuesday – October 12, 2021
Immediately Following Agenda Conference
Room 148 – Betty Easley Conference Center

1. Draft Review of the 2021 Ten-Year Site Plan of Florida's Electric Utilities (Attachment 1)
2. Draft 2021 Status Report of Utility Storm Protection Activities, pursaunt to 366.96,(10), F.S (Attachment 2)
3. General Counsel's Report
4. Executive Director's Report
5. Other Matters

BB/aml

OUTSIDE PERSONS WISHING TO ADDRESS THE COMMISSION ON ANY OF THE AGENDAED ITEMS SHOULD CONTACT THE OFFICE OF THE EXECUTIVE DIRECTOR AT (850) 413-6463.

Attachment 1

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 29, 2021

TO: Braulio L. Baez, Executive Director

FROM: Donald Phillips, Engineering Specialist II, Division of Engineering DP POC LK TB

RE: Review of the 2021 Ten-Year Site Plans of Florida Electric Utilities

CRITICAL INFORMATION: Place on October 12, 2021 Internal Affairs Agenda. Approval by the Commission is required by December 31, 2021.

Pursuant to Section 186.801(2), F.S., the Commission is required to classify each generating electric utility's Ten-Year Site Plan as either "suitable" or "unsuitable" by December 31 each year. The attached draft satisfies this requirement and its approval by the Commission is sought.

Please let me or Phillip Ellis know if you have any questions or need additional information in reference to the attached document.

DP:pz

Attachment

cc: Deputy Executive Director – TECH (M. Futrell)
Division of Engineering (P. Ellis, L. King, T. Ballinger)

DRAFT 09-24-2021

REVIEW OF THE

2021 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

OCTOBER 2021

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List of Ten-Year Site Plan Utilities

Name	Abbreviation
Investor-Owned Electric Utilities	
Florida Power & Light Company	FPL
Duke Energy Florida, LLC	DEF
Tampa Electric Company	TECO
Gulf Power Company	GPC
Municipal Electric Utilities	
Florida Municipal Power Agency	FMPA
Gainesville Regional Utilities	GRU
JEA	JEA
Lakeland Electric	LAK
Orlando Utilities Commission	OUC
City of Tallahassee Utilities	TAL
Rural Electric Cooperatives	
Seminole Electric Cooperative	SEC

Unit Type and Fuel Abbreviations

Reference	Name	Abbreviation
Unit Type	Battery Storage	BAT
	Combined Cycle	CC
	Combustion Turbine	CT
	Hydroelectric	HY
	Internal Combustion	IC
	Photovoltaic	PV
	Steam Turbine	ST
Fuel Type	Distillate Fuel Oil	DFO
	Bituminous Coal	BIT
	Natural Gas	NG

Executive Summary

Integrated resource planning (IRP) is a utility process that includes a cost-effective combination of demand-side resources and supply-side resources. While each utility has slightly different approaches to IRP, some things are consistent across the industry. Each utility must update its load forecast assumptions based on Florida Public Service Commission (Commission) decisions in various dockets, such as demand-side management goals. Changes in government mandates, such as appliance efficiency standards, building codes, and environmental requirements must also be considered. Other updates involve input assumptions like demographics, financial parameters, generating unit operating characteristics, and fuel costs which are more fluid and do not require prior approval by the Commission. Each utility then conducts a reliability analysis to determine when resources may be needed to meet expected load. Next, an initial screening of demand-side and supply-side resources is performed to find candidates that meet the expected resource need. The demand-side and supply-side resources are combined in various scenarios to decide which combination meets the need most cost-effectively. After the completion of all these components, utility management reviews the results of the varying analyses and the utility's Ten-Year Site Plan (TYSP) is produced as the culmination of the IRP process. Commission Rules also require the utilities to provide aggregate data which provides an overview of the State of Florida electric grid.

The Commission's annual review of utility Ten-Year Site Plans is non-binding as required by Florida Statutes, but it does provide state, regional, and local agencies advance notice of proposed power plants and transmission facilities. Any concerns identified during the review of the utilities' Ten-Year Site Plans may be addressed by the Commission at a formal public hearing, such as a power plant need determination proceeding. While Florida Statutes and Commission Rules do not specifically define IRP, they do provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Pursuant to Section 186.801, Florida Statutes (F.S.), each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2021 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

All findings of the Commission are made available to the Florida Department of Environmental Protection for its consideration at any subsequent certification proceeding pursuant to the

[1] Investor-owned utilities filing 2021 Ten-Year Site Plans include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2021 Ten-Year Site Plans include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2021 Ten-Year Site Plan.

Electrical Power Plant Siting Act or the Electric Transmission Line Siting Act.[2] In addition, this document is sent to the Florida Department of Agriculture and Consumer Services pursuant to Section 377.703(2)(e), F.S., which requires the Commission provide a report on electricity and natural gas forecasts.

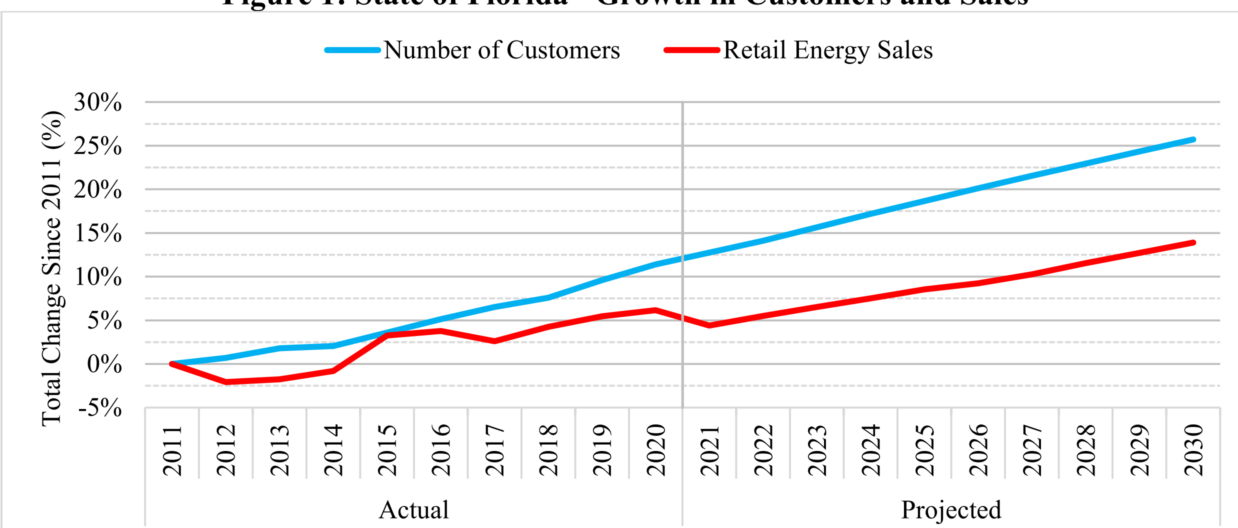
Review of the 2021 Ten-Year Site Plans

The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's electric utilities regarding load forecasting, renewable generation, and traditional generation.

Load Forecasting

Forecasting load growth is an important component of system planning for Florida's electric utilities. Florida's electric utilities reduce the rate of growth in customer peak demand and annual energy consumption through demand-side management programs. The Commission, through its authority granted by Sections 366.80 through 366.83 and Section 403.519, F.S., otherwise known as the Florida Energy Efficiency and Conservation Act (FEECA), encourages demand-side management by establishing goals for the reduction of seasonal peak demand and annual energy consumption for those utilities under its jurisdiction. Figure 1 details these trends.

Figure 1: State of Florida - Growth in Customers and Sales



Source: FRCC 2021 Regional Load and Resource Plan

[2] The Electrical Power Plant Siting Act is Sections 403.501 through 403.518, F.S. Pursuant to Section 403.519, F.S., the Commission is the exclusive forum for the determination of need for an electrical power plant. The Electric Transmission Line Siting Act is Sections 403.52 through 403.5365, F.S. Pursuant to Section 403.537, F.S., the Commission is the sole forum for the determination of need for a transmission line.

Renewable Generation

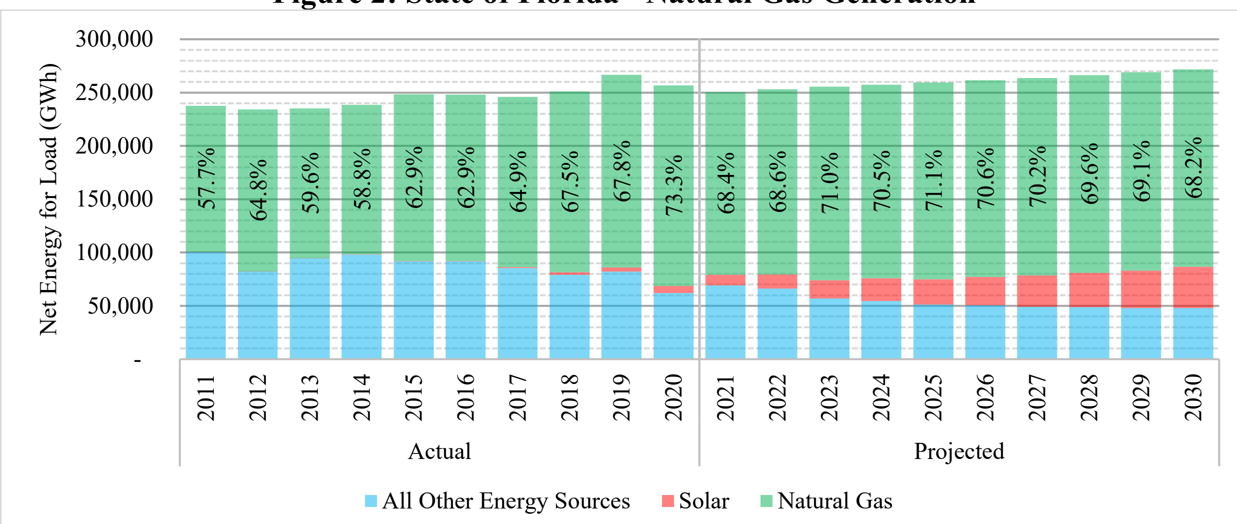
Renewable resources continue to expand in Florida, with approximately 6,156 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar photovoltaic (PV) generation which makes up approximately 75 percent of Florida's renewables. Notably, Florida electric customers had installed 835 MW of demand-side renewable capacity by the end of 2020, an increase of 63 percent from 2019.

Florida's total renewable resources are expected to increase by an estimated 15,055 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels. Also, FPL, GPC, and TECO have reported solar connected battery storage additions totaling 1,469 MW which are projected to increase the firm capacity available during system peaks.

Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,501 MW of traditional generation over the planning horizon. Natural gas electric generation, as a percent of net energy for load (NEL), is expected to range between an 68 and 71 percent NEL over the planning horizon. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida compared to solar and all other energy sources combined.

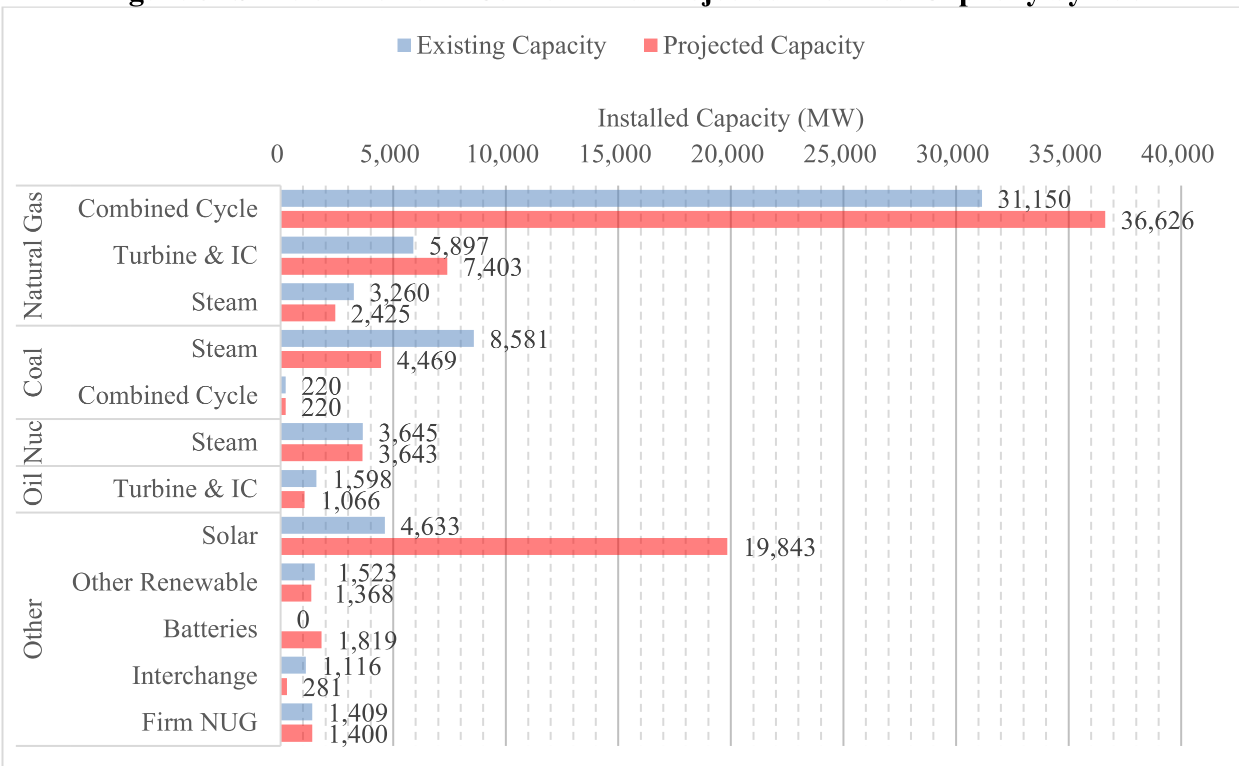
Figure 2: State of Florida - Natural Gas Generation



Source: FRCC 2012-2021 Regional Load and Resource Plan

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2021 Ten-Year Site Plans. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. While natural gas-fired generating units represent a majority of capacity within the state, renewable capacity additions make up the majority of the projected net increase in generation capacity over the planning period. Given its projected net increase, renewable capacity is expected to surpass coal generation during the 10-year planning period, becoming the second highest installed capacity source in the state.

Figure 3: State of Florida - Current and Projected Installed Capacity by Fuel



Source: FRCC 2021 Regional Load and Resource Plan & TYSP Utilities's Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local and state agencies to assist in the certification process. During the next 10 years, there are no new units planned that require a determination of need from the Commission.

Future Concerns

Florida's electric utilities must also consider changes in environmental regulations associated with existing generators and planned generation to meet Florida's electric needs. Developments in U.S. Environmental Protection Agency (EPA) regulations may impact Florida's existing generation fleet and proposed new facilities. For example, in January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the Affordable Clean Energy (ACE) rule addressing greenhouse gas emissions from electric power plants and remanded it to the EPA. However, as the Court did not expressly reinstate the Clean Power Plan (CPP), the EPA understands the decision as leaving neither of those rules, and thus no Clean Air Act (CAA) section 111(d) regulation, in place with respect to greenhouse gas emissions from electric generating units. These and other relevant EPA actions are further discussed in the Traditional Generation Section.

Conclusion

The Commission has reviewed the 2021 Ten-Year Site Plans of Florida's electric utilities and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2021 Ten-Year Site Plans to be suitable for planning purposes. Since the plans are not a binding plan of action for electric utilities, the Commission's classification of these plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

Introduction

The Ten-Year Site Plans of Florida's electric utilities are the culmination of an integrated resource plan which is designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. The Ten-Year Site Plans are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

For any new proposed power plants and transmission facilities, certification proceedings under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, F.S., or the Florida Electric Transmission Line Siting Act, Sections 403.52 through 403.5365, F.S., will include more detailed information than is provided in the Ten-Year Site Plans. The Commission is the exclusive forum for determination of need for electrical power plants, pursuant to Section 403.519, F.S., and for transmission lines, pursuant to Section 403.537, F.S. The Ten-Year Site Plans are not intended to be comprehensive, and therefore may not have sufficient information to allow regional planning councils, water management districts, and other reviewing state and local agencies to evaluate site-specific issues within their respective jurisdictions. Other regulatory processes may require the electric utilities to provide additional information as needed.

Statutory Authority

Section 186.801, F.S., requires all major generating electric utilities submit a Ten-Year Site Plan to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each Ten-Year Site Plan and makes a non-binding determination as to whether it is suitable or unsuitable. The results of the Commission's study are contained in this report and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, and forward this information to the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Applicable Utilities

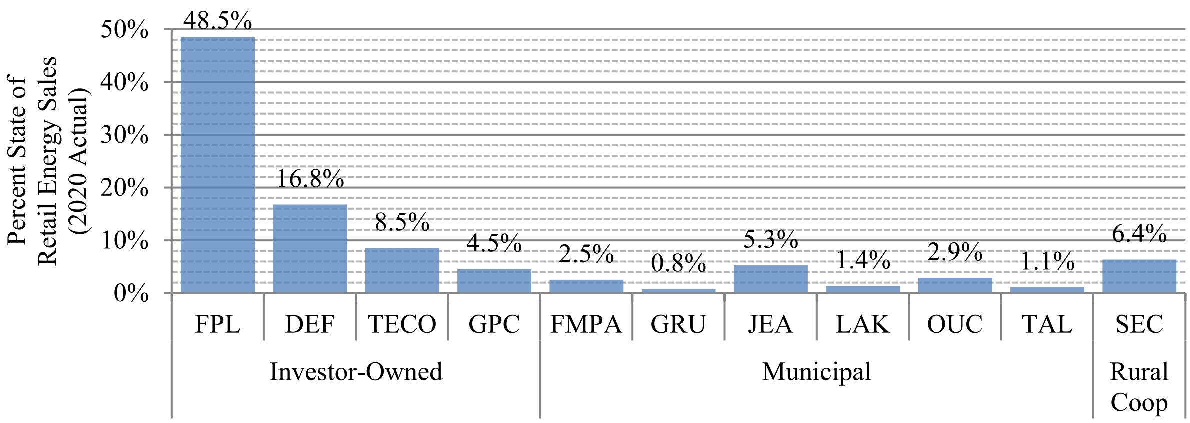
Florida is served by 57 electric utilities, including 5 investor-owned utilities, 34 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file a Ten-Year Site Plan with the Commission every year.

In 2021, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando

Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2021 Ten-Year Site Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2020. Combined, the reporting investor-owned utilities account for 78 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 20 percent of the state's retail energy sales.

Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Size



Source: 2021 Ten-Year Site Plans & FRCC 2021 Regional Load and Resource Plan

Required Content

The Commission requires each reporting utility to provide information on a variety of topics as required by Section 186.801(2) F.S. Schedules describe the utility's existing generation fleet, customer composition, demand and energy forecasts, fuel requirements, reserve margins, changes to existing capacity, and proposed power plants and transmission lines. The utilities also provide a narrative documenting the methodologies used to forecast customer demand and the identification of resources to meet that demand over the 10-year planning period. This information, supplemented by additional data requests, provides the basis of the Commission's review.

Additional Resources

The Florida Reliability Coordinating Council (FRCC) is tasked with reporting and collecting information on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. This provides aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. For certain comparisons, the Commission employs additional data from various government agencies, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

The Commission held a public workshop on August 11, 2021, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2021 Regional Load and Resource Plan and other related matters, including fuel supply reliability and the reliability considerations of utility solar generation additions. Additional presentations were made by the Southern Alliance for Clean Energy and Vote Solar.

Structure of the Commission's Review

The Commission's review is divided into multiple sections. The Statewide Perspective provides an overview of Florida as a whole, including discussions of load forecasting, renewable generation, and traditional generation. The Utility Perspectives provides more focus, discussing the various issues facing each electric utility and its unique situation. Comments collected from various review agencies, local governments, and other organizations are included in Appendix A.

Conclusion

Based on its review, the Commission finds all 11 reporting utilities' 2021 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity at a reasonable cost.

The Commission notes that the Ten-Year Site Plans are non-binding, and a classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the Ten-Year Site Plans. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

Statewide Perspective

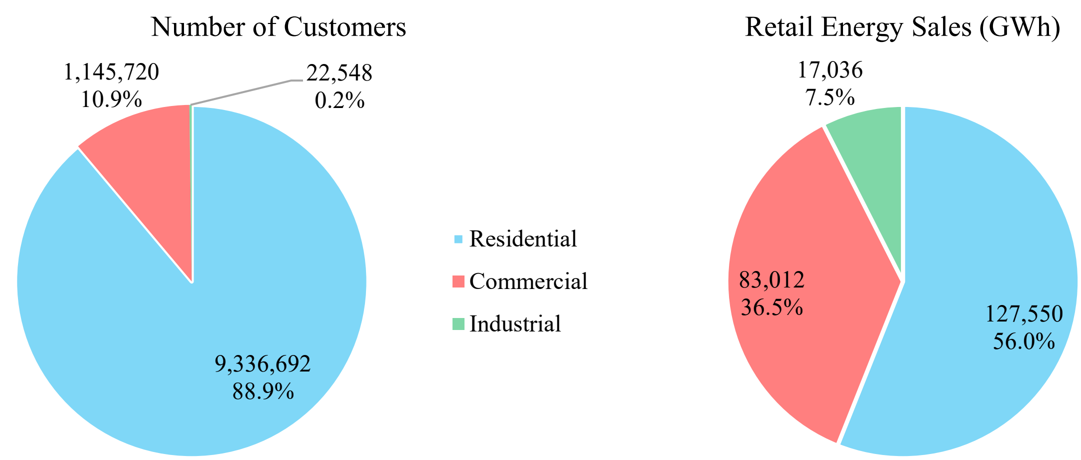
Load Forecasting

Forecasting load growth is an important component of the IRP process for Florida's electric utilities. In order to maintain system reliability, utilities must be prepared for future changes in electricity consumption, including changes to the number of electric customers, customer usage patterns, building codes, appliance efficiency standards, new technologies, and the role of demand-side management.

Electric Customer Composition

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2021, residential customers account for 88.9 percent of the total, followed by commercial (10.9 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5. Commercial and industrial customers make up a sizeable percentage of energy sales due to their higher energy usage per customer.

Figure 5: State of Florida - Electric Customer Composition in 2020



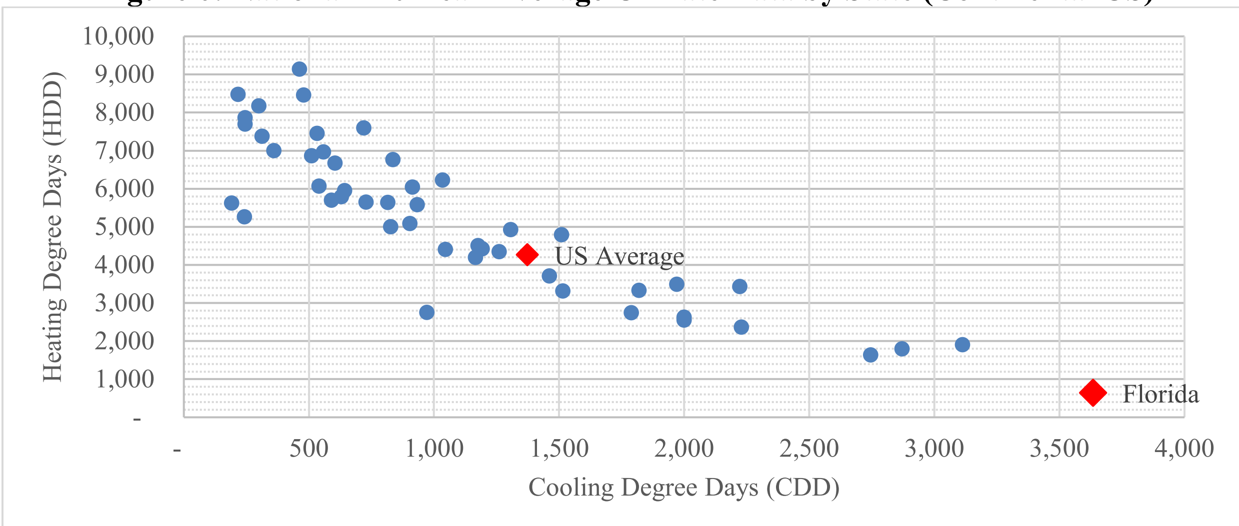
Source: FRC-C 2021 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 56 percent of retail energy sales in 2020, compared to a national average of approximately 34 percent.[3] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. In addition, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

[3] U.S. Energy Information Administration June 2021 Electric Power Monthly.

Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown in Figure 6. Other states tend to rely upon alternative fuels for heating, but Florida's heavy use of electricity results in high winter peak demand.

Figure 6: National - 20 Year Average Climate Data by State (Continental US)

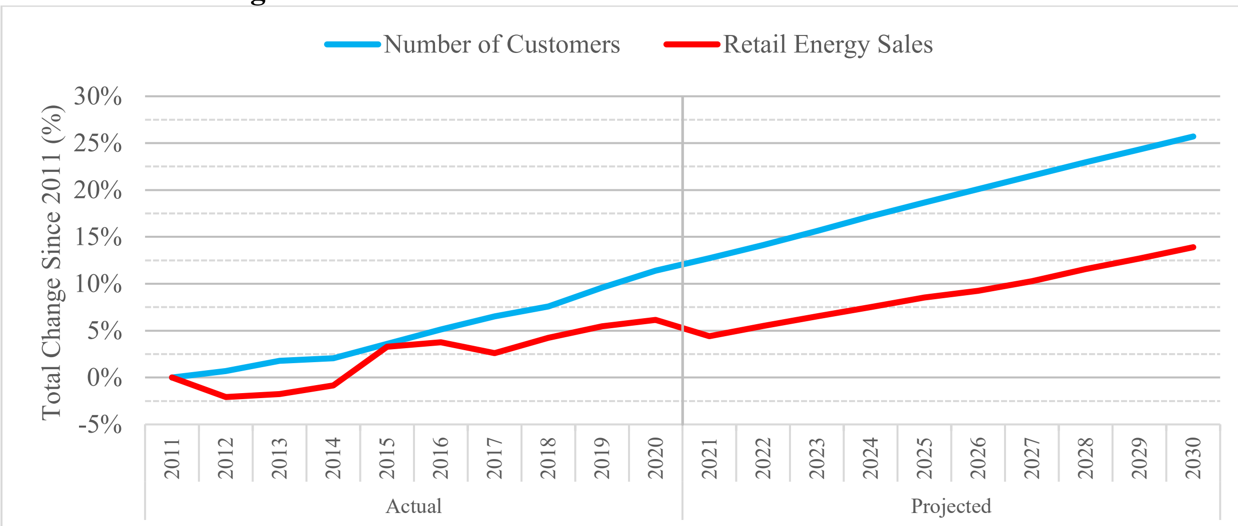


Source: National Oceanic and Atmospheric Administration Data

Growth Projections

For the next 10-year period, Florida's retail energy sales, weather normalized, are projected to grow at 0.97 percent per year, compared to the 0.67 percent actual annual increase experienced during the 2011-2020 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.22 percent for the next 10-year period, similar to the 1.21 percent actual annual increase experienced during the last decade. These trends are showcased in Figure 7.

Figure 7: State of Florida - Growth in Customers and Sales



Source: FRCC 2021 Regional Load and Resource Plan

The projected retail energy sales trend reflects the product of the utilities' forecasted number of customers and forecasted energy consumption per customer. The key factor affecting utilities' number of customers is population growth. The key factors affecting utilities' use-per-customer includes weather, the economy, energy prices, and energy efficiency; hence, the corresponding information is utilized to develop the forecast models for projecting the future growth of use-per-customer. The projected growth rate of retail energy sales is impacted by these underlying key factors.

FPL and GPC indicated that improvements to energy efficiency are expected to continuously play a role in the level of growth of per customer energy usage over the next several years. DEF reported that, for residential and commercial classes, the non-weather trends in per customer usage are primarily driven by fluctuations in electric price, end-use appliance saturation and efficiency improvement, building codes, and housing type/size. DEF also noted that customer self-generation has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generation, and some residential and commercial customers have installed solar panels behind their meters, thereby reducing consumption from the power grid. Offsetting these factors to some extent, DEF noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal. TECO confirmed that increases in appliance/lighting efficiencies, energy efficiency of new homes, conservation efforts and housing mix are the primary drivers affecting the per customer usage. Other TYSP Utilities likewise revealed that the downward pressure to the growth trend of per customer energy consumption is due to advancements in efficient technologies, renewable generation, and alternative energy sources.

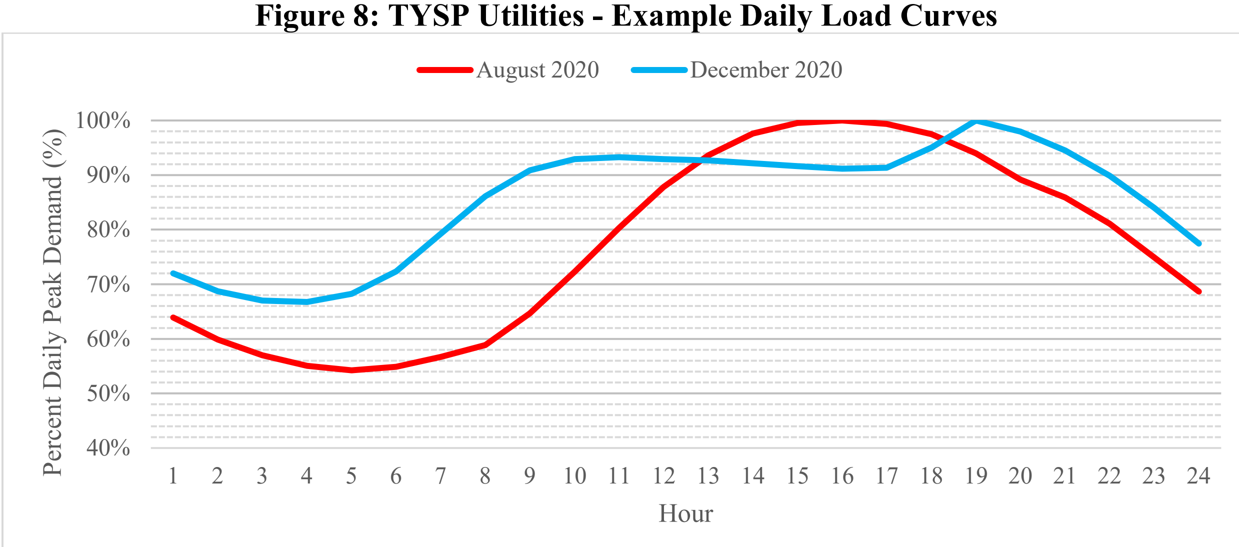
As shown in Figure 7, Florida utilities' total retail energy sales reached a historic peak in 2020. This is primarily due to the COVID-19 Pandemic which resulted in more people working and/or schooling from home. All of the TYSP Utilities reported decreased commercial energy sales and some reported decreased industrial energy sales as well in 2020 which was off-set by the growth of the residential energy sales. For the forecast period, the annual growth rate of the residential sales may return to the pre-Pandemic level in 2021 with the waning of the "stay-at-home" status of customers. However, some potential COVID-related concerns remain which include uncertainty in the commercial sector as business floor space requirements may be permanently scaled back from previously planned levels and some closed small businesses may not be re-purposed or re-open for some time.

Peak Demand

The aggregation of each individual customer's electric consumption must be met at all times by Florida's electric utilities to ensure reliable service. The time at which customers demand the most energy simultaneously is referred to as peak demand. While retail energy sales dictate the amount of fuel consumed by the electric utilities to deliver energy, peak demand determines the amount of generating capacity required to deliver that energy at a single moment in time.

Seasonal weather patterns are a primary factor, with peak demands calculated separately for the summer and winter periods annually. The influence of residential customers is evident in the determination of these seasonal peaks, as they correspond to times of increased usage to meet home heating (winter) and cooling (summer) demand. Figure 8 illustrates a daily load curve for a typical day for each season, based on average hourly peak demand during the months of August and December. In summer, air-conditioning needs increase throughout the day, climbing steadily until a peak is reached in the late afternoon and then declining into the evening. In winter, electric heat and electric water heating produce a higher base level of usage, with a spike in the morning and an additional spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

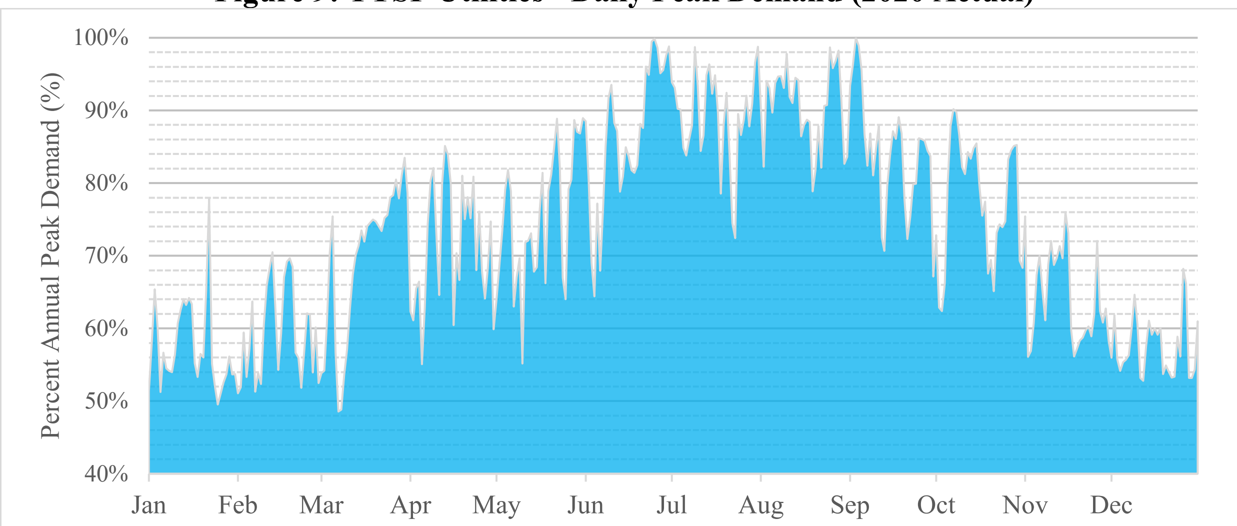


Source: TYSP Utilities' Data Responses

Florida is typically a summer-peaking state, meaning that the summer peak demand generally exceeds winter peak demand, and therefore controls the amount of generation required. Higher temperatures in summer also reduce the efficiency of generation, with high water temperatures reducing the quality of cooling provided, and can sometimes limit the quantity as units may be required to operate at reduced power or go offline based on environmental permits. Conversely, in winter, utilities can take advantage of lower ambient air and water temperatures to produce more electricity from a power plant.

As daily load varies, so do seasonal loads. Figure 9 shows the 2020 daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. A particularly mild winter in 2020 reduced the winter seasonal demand peaks due to reduced heating load. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

Figure 9: TYSP Utilities - Daily Peak Demand (2020 Actual)



Source: TYSP Utilities' Data Responses (Investor-Owned Utilities Only)

Florida's utilities assume normalized weather in forecasts of peak demand. During operation of their systems, they continuously monitor short-term weather patterns. Utilities adjust maintenance schedules to ensure the highest unit availability during the utility's projected peak demand, bringing units back online if necessary or delaying maintenance until after a weather system has passed.

Electric Vehicles

Utilities also examine other trends that may impact customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles. The reporting electric utilities estimate approximately 79,552 electric plug-in vehicles will be operating in Florida by the end of 2021. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 10, 2021, at 17.35 million vehicles, resulting in an approximate 0.46 percent penetration rate of electric vehicles.[4]

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 1. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 694,376 electric vehicles operating within the electric service territories by the end of 2030.

Table 1: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory

Year	FPL	DEF	TECO	GULF	JEA	GRU	LAK*	TAL	Total
2021	49,282	17,473	6,530	1,981	2,335	501	477	1,420	79,999
2022	59,636	23,235	7,815	2,397	2,764	622	N/A	1,435	97,904
2023	75,862	31,809	9,321	3,049	3,297	767	N/A	1,449	125,554
2024	97,925	43,235	11,052	3,936	3,924	941	N/A	1,463	162,476
2025	127,482	57,796	13,049	5,124	4,642	1,147	N/A	1,478	210,718
2026	168,680	73,955	15,183	6,780	5,450	1,388	N/A	1,493	272,929
2027	222,806	91,689	17,456	8,955	6351	1,669	N/A	1,508	350,434
2028	291,594	111,252	19,869	11,720	7366	1,995	N/A	1,524	445,320
2029	375,053	132,778	22,425	15,074	8502	2,368	N/A	1,600	557,800
2030	479,126	156,694	25,125	19,257	9766	2,791	N/A	1,616	694,375

Source: TYSP Utilities' Data Responses
*LAK did not provide projected electric vehicle counts for years 2022-2030; 2021 estimate is based on DMV data for Polk County

The major drivers of electric vehicle growth include lower fuel costs and emissions, increased availability of charging infrastructure, and federal tax credits and state incentives associated with the purchase of an electric vehicle.

Private entities, municipalities, government agencies, and recently electric utilities are expanding charging infrastructure throughout the state to meet this expected growth in electric vehicles as well as to promote electric vehicle ownership. As a result of legislation passed in 2020, the Commission and the State Energy Office assisted the Florida Department of Transportation in coordinating, developing, and recommending a master plan for the development of electric vehicle charging station infrastructure along the State Highway System. The EV Infrastructure Master Plan was published in July 2021.[5]

Table 2 illustrates the reporting electric utilities' projections of public electric vehicle charging stations through 2030. While approximately 6,000 charging stations are estimated to be available in 2021, a projected 29,000 charging stations are anticipated by 2030.

[4] Florida Department of Highway Safety and Motor Vehicles January 2020 Vehicle and Vessel Reports and Statistics.
[5] Florida Department of Transportation, *EV Infrastructure Master Plan,* published July 2021.

Table 2: TYSP Utilities - Estimated Number of Public PEV Charging Stations by Service Territory

Year	FPL	DEF*	TECO	GULF	JEA	GRU	LAK**	TAL	Total
2021	4,007	1,006	386	165	97	78	18	34	5,791
2022	5,286	N/A	433	218	110	86	N/A	34	6,167
2023	7,320	N/A	479	302	125	94	N/A	34	8,354
2024	9,210	N/A	525	380	141	104	N/A	34	10,394
2025	11,437	N/A	571	472	159	114	N/A	38	12,791
2026	13,815	N/A	617	570	178	126	N/A	38	15,344
2027	16,534	N/A	663	682	199	138	N/A	38	18,254
2028	20,377	N/A	710	841	222	152	N/A	40	22,342
2029	24,580	N/A	756	1,014	247	187	N/A	40	26,824
2030	26,857	N/A	802	1,108	275	184	N/A	40	29,266

Source: TYSP Utilities' Data Responses
* DEF is currently developing a charger forecasting tool; 2021 estimate is based on year-end 2020 actuals.
** LAK did not provide projected public PEV charging station counts for years 2022-2030; 2021 estimate is based on DMV data for Polk County.

Table 3 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2030. Across the TYSP Utilities, anticipated growth would result in an annual energy consumption of 3,387.4 gigawatt-hours (GWh) by 2030. Despite this relatively rapid growth rate, current estimates represent an impact of less than 1.5 percent on net energy for load by 2030.

Table 3: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)

Year	FPL	DEF	TECO	GULF	JEA	GRU	LAK*	TAL*	Total
2021	42.6	7.6	27.6	1.0	8.5	1.8	N/A	N/A	89.1
2022	112.3	27.1	32.9	2.4	10.7	2.2	N/A	N/A	187.7
2023	216.9	54.1	39.2	4.8	13.4	2.8	N/A	N/A	331.1
2024	361.7	91.9	46.4	8.0	16.6	3.4	N/A	N/A	527.9
2025	554.6	140.7	54.6	12.2	20.3	4.1	N/A	N/A	786.6
2026	812.9	199.1	63.5	18.2	24.4	5.0	N/A	N/A	1,123.1
2027	1,144.6	263.8	72.9	26.0	29.0	6.0	N/A	N/A	1,542.3
2028	1,558.3	336.3	82.8	35.9	34.2	7.2	N/A	N/A	2,054.8
2029	2,056.2	414.9	93.4	48.0	40.0	8.5	N/A	N/A	2,661.0
2030	2,660.0	503.3	104.5	63.0	46.5	10.1	N/A	N/A	3,387.4

Source: TYSP Utilities' Data Responses
*TAL and LAK did not provide estimates of electric vehicle annual energy consumption.

The effect of increased electric vehicle ownership on peak demand is difficult to determine. While comparable in electric demand to a home air conditioning system, the time of charging and whether charging would be shifted away from periods of peak demand are uncertain. As electric vehicle ownership increases, the projected impacts of electric vehicles on system peak demand should become clearer and electric utilities will be better positioned to respond accordingly.

In order to investigate potential unknowns associated with the electric vehicle energy market in Florida, several utilities have initiated electric vehicle pilot programs, either as independent programs or as part of rate case settlement agreements. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Utilities will note key findings and track metrics of interest within these pilot programs to help inform the Commission regarding the future power needs of electric vehicles in Florida.

Demand-Side Management (DSM)

Florida's electric utilities also consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include: turning off lights and fans in vacant rooms, increasing thermostat settings, and purchasing appliances that go beyond efficiency standards. While a certain portion of customers will engage in these activities without incentives due to economic, aesthetic, or environmental concerns, other customers may lack information or require additional incentives. DSM represents an area where Florida's electric utilities can empower and educate its customers to make choices that reduce peak load and annual energy consumption.

Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth rates in seasonal peak demand and annual energy consumption by establishing FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set goals for seasonal demand and annual energy reduction for seven electric utilities, known as the FEECA Utilities. These include the five investor-owned electric utilities, FPL, DEF, TECO, GPC, and Florida Public Utility Company (which is a non-generating utility and therefore does not file a Ten-Year Site Plan) and two municipal electric utilities, JEA and OUC. The FEECA Utilities represented approximately 87 percent of 2020 retail electric sales in Florida.

The FEECA Utilities currently offer demand-side management programs for residential, commercial, and industrial customers. Energy audit programs are designed to provide an overview of customer energy usage and to evaluate conservation opportunities, including behavioral changes, low-cost measures customers can undertake themselves, and participation in utility-sponsored DSM programs.

The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024. The Commission found that it was in the public interest to continue with the goals established in the 2014 FEECA goal-setting proceeding. All FEECA Utilities that filed a 2021 Ten-Year Site Plan incorporated in their planning the impacts of the established DSM goals through 2024.

Each FEECA electric utility was required to submit a proposed DSM Plan designed to meet the goals established in the most recent FEECA goal-setting proceeding within 90 days of the final order establishing the goals. Each FEECA electric utility submitted a proposed DSM Plan on or before February 24, 2020. On May 12, 2020, and June 24, 2020, the Commission approved the DSM Plans proposed by OUC and JEA, respectively. On July 7, 2020, the Commission voted to approve the DSM Plans proposed by the remaining FEECA electric utilities.

DSM Programs

DSM Programs generally are divided into three categories: interruptible load, load management, and energy efficiency. The first two are considered dispatchable, and are collectively known as demand response, meaning that the utility can call upon them during a period of peak demand or other reliability concerns, but otherwise they are not utilized. In contrast, energy efficiency measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible load is achieved through the use of agreements with large customers to allow the utility to interrupt the customer's load, reducing the generation required to meet system demand. Interrupted customers may use back-up generation to fill their energy needs, or cease operation until the interruption has passed. A subtype of interruptible load is curtailable load, which allow the utility to interrupt only a portion of the customer's load. In exchange for the ability to interrupt these customers, the utility offers a discounted rate for energy or other credits which are paid for by all ratepayers.

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak.

As of December 31, 2020, demand response available for reduction of peak load is 3,114 MW for summer peak and 2,917 MW for winter peak. Demand response is anticipated to increase to approximately 3,437 MW for summer peak and 3,162 MW for winter peak by 2030.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of December 31, 2020, energy efficiency is responsible for peak load reductions of 4,518 MW for summer peak and 4,027 MW for winter peak. Energy efficiency is anticipated to increase to approximately 6,296 MW for summer peak and 5,527 MW for winter peak by 2030.

Forecast Load & Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated in Figure 10. The forecasts shown below are based upon normalized weather conditions, while the historic demand and energy values represent the actual impact of weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in the summer and electric heating in the winter, so both seasons experience a great deal of variability due to severe weather conditions.

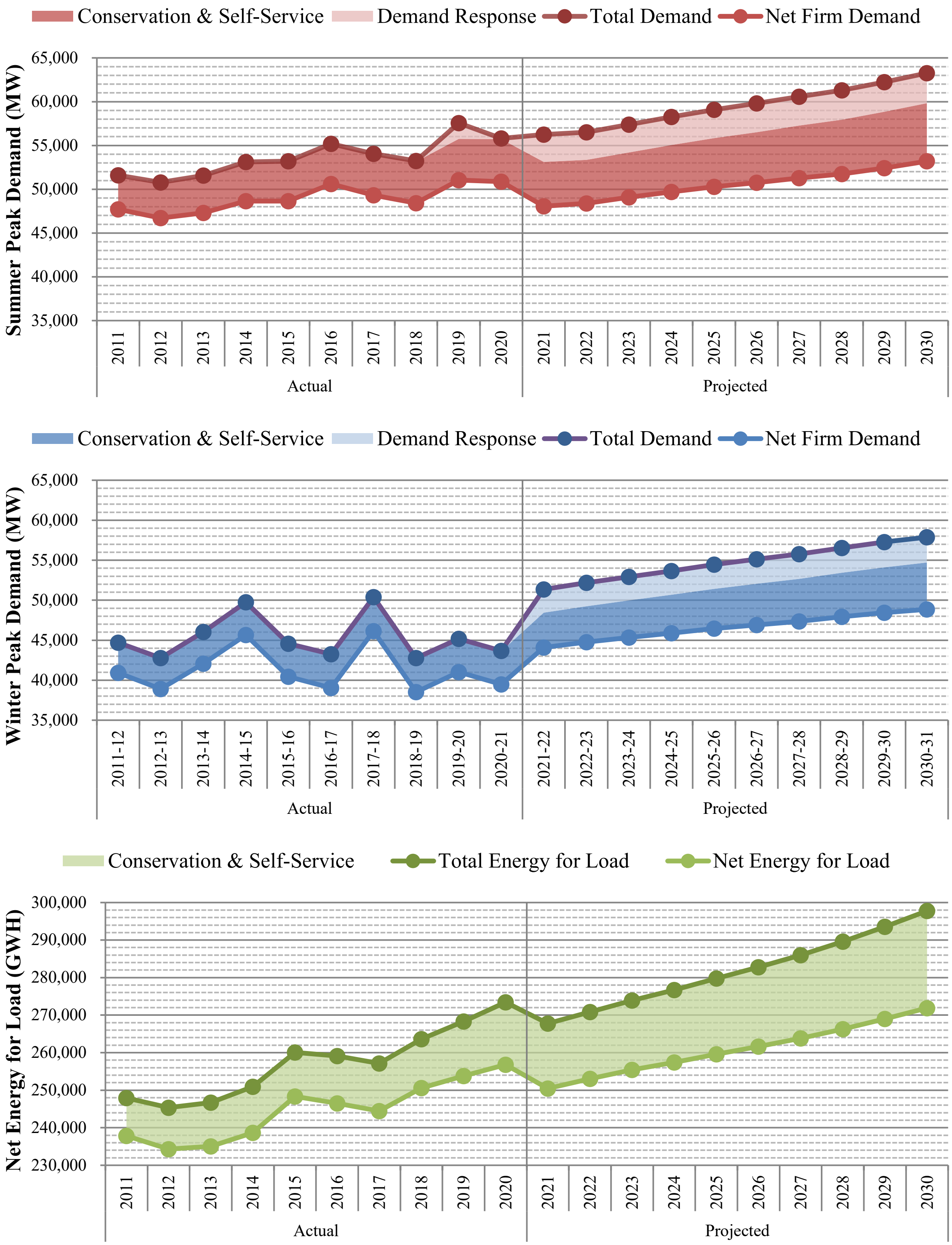
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities.

Demand response is included in Figure 10 in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount of demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated.

For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on operating conditions in the future, if an electric utility has sufficient generating units, and it is economical to serve all customers' load demand, response would not be activated or only partially activated in the future.

As previously discussed, Florida is normally a summer-peaking state and was for the past 10 years. This trend is anticipated to continue, with the next 10 forecasted years all anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities anticipate a gradual increase in both summer and winter net firm demand during the planning period.

Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy



Source: FRCC 2021 Regional Load and Resource Plan

Forecast Methodology

Florida's electric utilities perform forecasts of peak demand and annual energy sales using various forecasting models, including econometric and end-use models, and other forecasting techniques such as surveys. In the development of econometric models, the utilities use historical data sets including dependent variables (e.g. summer peak demand per customer, residential energy use per customer) and independent variables (e.g. cooling degree days, real personal income, etc.) to infer relationships between the two types of variables. These historical relationships, combined with available forecasts of the independent variables and the utilities' forecasts of customers, are then used to forecast the peak demand and energy sales. For some customer classes, such as industrial customers, surveys may be conducted to determine the customers' expectations for their own future electricity consumption.

The forecasts also account for demand-side management programs. Sales models are prepared by revenue class (e.g. residential, small and large commercial, small and large industrial, etc.). Commonly, the results of the models must be adjusted to take into account exogenous impacts, such as the impact of the recent growth in plug-in electric vehicles and distributed generation.

End-use models are sometimes used to project energy use in conjunction with econometric models. These models can capture trends in appliance and equipment saturation and efficiency, as well as building size and thermal efficiency, on customers' energy use. If such end-use models are not used, the econometric models for energy often include an index comprised of efficiency standards for air conditioning, heating, and appliances, as well as construction codes for recently built homes and commercial buildings.

Florida's electric utilities rely upon data which is sourced from public and private entities for historic and forecast values of specific independent variables used in econometric modeling. Public resources such as the University of Florida's Bureau of Economic and Business Research, which provides county-level data on population growth, and the U.S. Department of Commerce's Bureau of Labor Statistics, which publishes the Consumer Price Index, are utilized along with private forecasts for economic growth from macroeconomic experts, such as Moody's Analytics. By combining historic and forecast macroeconomic data with customer and climate data, Florida's electric utilities project future load conditions.

The various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to project load. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably.

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for our review involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2020 retail energy sales were compared to the forecasts made in 2015, 2016, and 2017. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy by applying a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast.

For the 2021 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2016 through 2020 to forecasts made between 2011 and 2017. In the period before the 2007-08 economic recession, electric utilities experienced a higher annual growth rate for retail energy sales than the post-recession period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities were not included in these projections. Therefore, the use of a metric that compares pre-recession forecasts with pre-recession actual data has a high rate of error.

Table 4 shows that the years prior to 2017 had relatively high forecast errors (the difference between the actual data and the forecasts made five years prior) due to the unexpected impact of the 2007-08 recession and its impact on retail energy sales in Florida. However, the forecast errors have returned to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the actual sales data provided in the 2017 Ten-Year Site Plans. The forecasting error rates (five-year rolling average and/or absolute average) derived from the 2018 to 2020 TYSP Utilities' forecasts show continued decreases.

Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts (Five-Year Rolling Average)

Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2012	2012 - 2008	2009 - 2003	15.22%	15.22%
2013	2013 - 2009	2010 - 2004	16.27%	16.27%
2014	2014 - 2010	2011 - 2005	14.99%	14.99%
2015	2015 - 2011	2012 - 2006	12.55%	12.55%
2016	2016 - 2012	2013 - 2007	9.19%	9.19%
2017	2017 - 2013	2014 - 2008	6.07%	6.07%
2018	2018 - 2014	2015 - 2009	3.58%	3.58%
2019	2019 - 2015	2016 - 2010	2.26%	2.42%
2020	2020 - 2016	2017 - 2011	1.68%	2.12%

Source: 2003-2021 Ten-Year Site Plans

To verify whether more recent forecasts bear lower error rates, an additional analysis was conducted to determine with more detail the source of high error rates in terms of forecast timing. Table 5 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of three- to five-years used in the analysis.

As displayed in Table 5, the utilities' retail energy sales forecasts show a large positive error during the recession-impacted period of 2009 through 2014. Starting in 2015, the error rates have declined considerably; and, the error rates calculated based on recent years' Ten-Year Site Plans continue to show lower forecast error rates, compared to the peak value of the error rates related to 2009-2014 sales forecasts. Additionally, the last three years' two-year ahead forecasts, the last two years' three-year ahead forecasts, and the last year's four-year ahead forecast all bear slightly negative error rates (under-forecasts). The current Ten-Year Site Plans also shows a very small error rate with respect to both average and absolute average three to five year error percentages. However, the one-year ahead forecast error was increased significantly and becomes the highest within the last seven years. This reflects the impact of the unpredicted COVID-19 Pandemic event on the accuracy of the utilities' sales forecast.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2009	12.05%	12.25%	14.58%	14.01%	12.79%	10.27%	13.61%	13.61%
2010	13.03%	15.68%	14.99%	13.81%	10.65%	-0.65%	14.83%	14.83%
2011	21.67%	20.91%	20.22%	17.14%	3.89%	0.18%	19.42%	19.42%
2012	26.43%	26.12%	23.16%	8.58%	4.01%	3.81%	19.29%	19.29%
2013	28.71%	26.42%	10.11%	6.09%	5.69%	3.08%	14.21%	14.21%
2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	7.21%	7.21%
2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	2.63%	2.63%
2016	4.33%	4.38%	2.28%	1.25%	0.20%	-0.97%	2.64%	2.64%
2017	6.99%	4.93%	3.59%	2.53%	1.57%	-0.07%	3.68%	3.68%
2018	4.28%	2.76%	1.76%	0.75%	-1.13%	-1.08%	1.76%	1.76%
2019	2.95%	2.04%	0.92%	-1.23%	-1.25%	-1.87%	0.58%	1.40%
2020	2.44%	1.27%	-0.97%	-1.07%	-1.91%	2.73%	-0.25%	1.10%

Source: 2003-2021 Ten-Year Site Plans

Barring any unforeseen economic crises, atypical weather patterns, or global health issues, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2020 in Table 5 than those significantly higher error rates that were shown in earlier years associated with the 2007-08 recession. However, the COVID-19 Pandemic has inflicted significant damage to the US economy, and there remains uncertainty as to when the economic impacts of the COVID-19 Pandemic will end. As a result, the actual retail energy sales could differ from what Florida utilities projected in 2020 and prior years. Consequently, the average forecasted energy sales error rates in the next few years may deviate from the lower levels recently recorded. It is important to recognize that the dynamic nature of the economy, the weather, and now even global health issues such as COVID-19 present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of energy sales forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(d), F.S., defines renewable energy in part, as follows:

> "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power.

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes, to also provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. The Section 366.91(2)(d), F.S., definition also includes the following language which recognizes the aforementioned cogeneration process:

> The term [Renewable Energy] includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 6,156 MW of firm and non-firm generation capacity, which represents 9.8 percent of Florida's overall generation capacity of 63,031 MW in 2020. Table 6 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	4,633	75.3%
Municipal Solid Waste	504	8.2%
Biomass	380	6.2%
Waste Heat	276	4.5%
Wind	272	4.4%
Hydroelectric	51	0.8%
Landfill Gas	41	0.7%
Renewable Total	**6,156**	**100.00%**

Source: FRCC 2021 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the total 6,156 MW of renewable generation, approximately 2,322 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fuel power plants. Solar generation contributes approximately 1,840 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida's utilities.

Non-Utility Renewable Generation

Approximately 29 percent of Florida's existing renewable generation capacity comes from non-utility generators, of which municipal solid waste and solar facilities make up the majority. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

> A utility's "full avoided costs" are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

If renewable energy generator can meet certain deliverability requirements, its capacity and energy output can be paid for under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's Ten-Year Site Plan. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not required. As-available energy is purchased at a rate equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer-Owned Renewable Generation

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2020, approximately 835 MW of renewable capacity from over 90,500 systems has been installed statewide. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 34 installations and 7.1 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 7: State of Florida - Customer-Owned Renewable Growth

Year	2013	2014	2015	2016	2017	2018	2019	2020
Number of Installations	6,697	8,581	11,626	15,994	24,166	37,862	59,508	90,552
Installed Capacity (MW)	63.04	79.8	107.5	141	205	317	514	835

Source: Annual Utility Reports

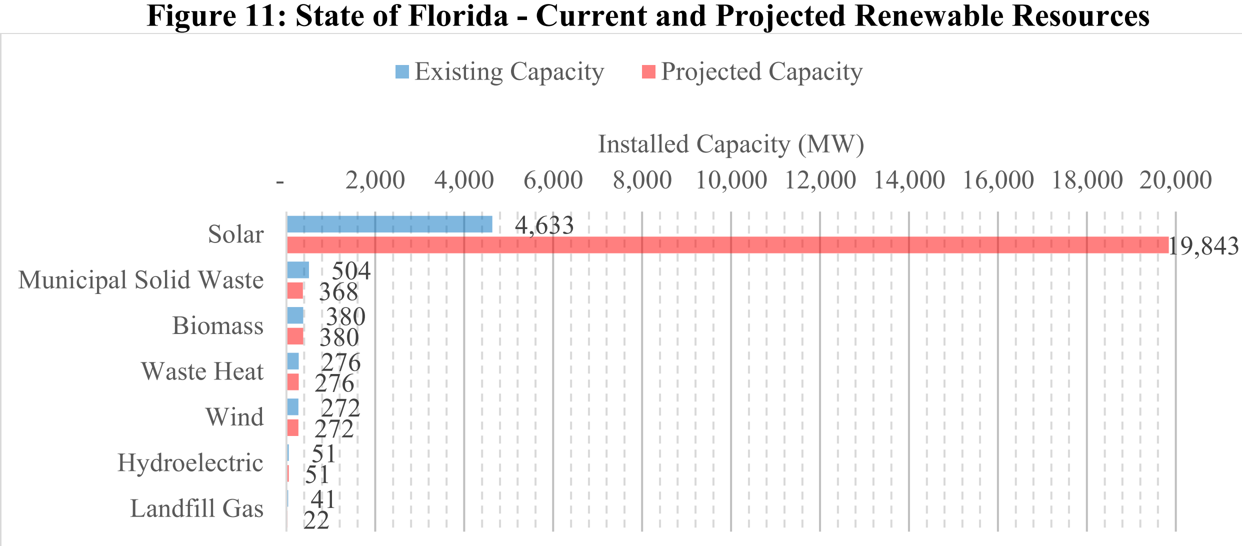
Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 3,382 MW of existing utility-owned solar capacity, approximately 1,735 MW, or about 51 percent, is considered firm.

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 15,055 MW over the 10-year planning period, a significant increase from last year's estimated 13,212 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

Figure 11: State of Florida - Current and Projected Renewable Resources

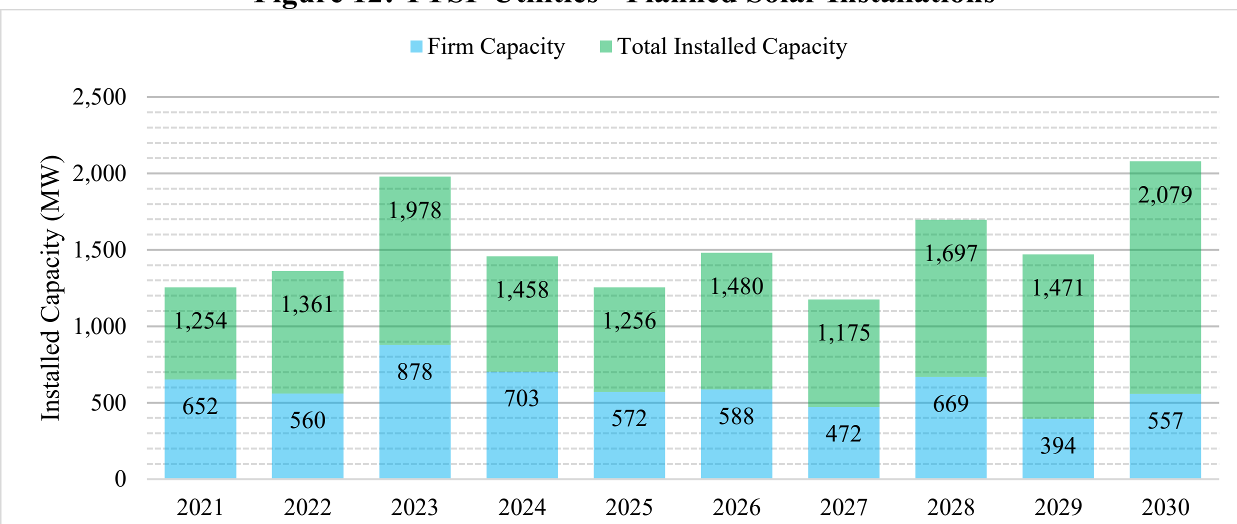


Source: FRCC 2021 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the 15,055 MW projected net increase in renewable capacity, firm resources contribute 6,017 MW, or about 40 percent, of the total. This net increase value takes into account that for some existing renewable facilities contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 15,209 MW to be installed. This consists of 12,471 MW of utility-owned solar and 2,738 MW of contracted solar. The firm contribution of solar varies by utility, with some having a set percentage value for all projects over the planning period, and others having a declining value as projects are added. Figure 12 provides an overview of the additional solar capacity generation planned within the next 10 years, as well as the amount considered firm for summer reserve margin planning.

Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2021 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Energy Storage Outlook

In addition to a number of electric grid related applications, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well. Energy storage technologies currently being researched include pumped hydropower, flywheels, compressed air, thermal storage, and battery storage. Of these technologies, Lithium ion (Li-ion) battery storage is being extensively researched due to its declining costs, operational characteristics, scalability, and siting flexibility.

As part of its 2016 Settlement, FPL has deployed 50 MW of non-firm capacity through its Battery Storage Pilot Program and has an additional 50 MW to build in 2021.[6] FPL's 2021 TYSP includes a total of 1,169 MW of solar charged battery storage additions over the next 10 years. Approximately 409 MW of this capacity is expected to be placed into service late in 2021 and will be located in Manatee County. An additional 60 MW will be divided into two 30 MW storage facilities, to be installed at two different locations, also late in 2021. FPL is projecting an additional 700 MW of unsited solar charged battery storage facilities to be added by 2030; 400 MW are projected to be located in the current FPL service area, while the remaining 300 MW are projected to be sited in the current Gulf territory.

DEF is expanding its battery storage with a 50 MW, non-firm capacity, Battery Storage Pilot Program as part of its 2017 Settlement.[7] The program includes six solar charged battery energy storage systems that are expected to be placed into service in 2021. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages. DEF will use the data gathered from the operation of these systems to evaluate future opportunities with battery storage.

TECO installed a 12.6 MW Li-Ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility is interconnected with the solar array and is expected to add 5.6 MW of firm capacity. Over the next 10 years, TECO expects to deploy approximately 300 MW of solar charged energy storage systems to meet system reliability needs, maximize solar energy production, and to avoid transmission and distribution investments.

[6] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[7] Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

Traditional Generation

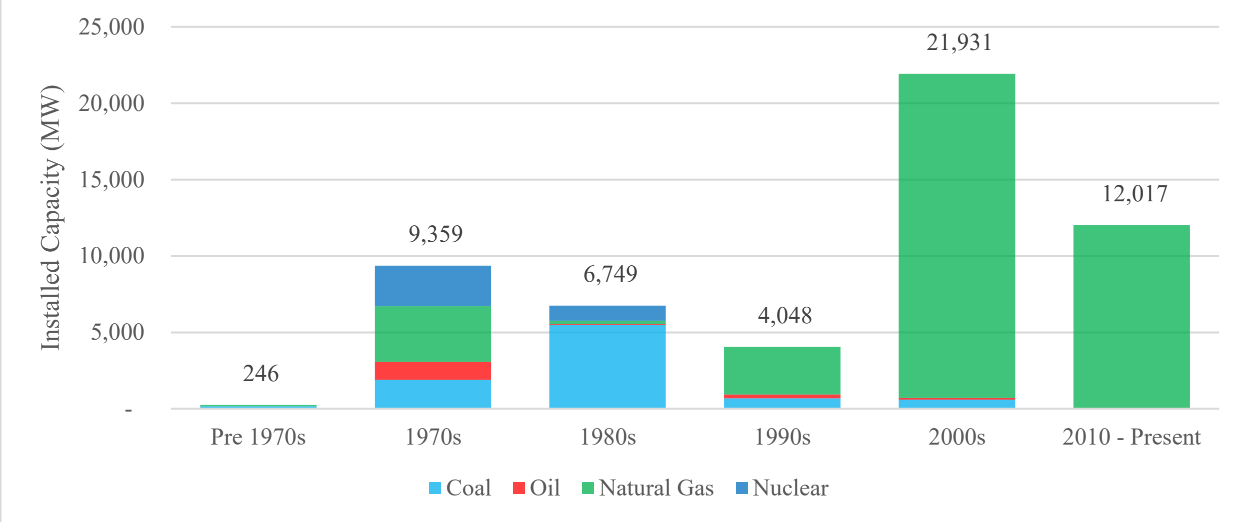
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. Due to forecasted increases in peak demand, further traditional resources are anticipated over the planning period.

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Previous to the oil embargo, Florida used oil-fired generation as its primary source of electricity until the increase in oil prices made this undesirable. Since that time, Florida's electric utilities have sought a variety of other fuel sources to diversify the state's generation fleet and more reliably and affordably serve customers. Numerous factors, including swings in fuel prices, availability, environmental concerns, and other factors have resulted in a variety of fuels powering Florida's electric grid. Solid fuels, such as coal and nuclear, increased during the shift away from oil-fired generation, and more recently natural gas has emerged as the dominant fuel type in Florida.

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 50 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 13 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 13: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2021 Regional Load and Resource Plan

The existing generating fleet will be impacted by several events over the planning period. New and proposed environmental regulations may require changes in unit dispatch, fuel switching, or installation of pollution control equipment which may reduce net capacity. Modernizations will allow more efficient resources to replace older generation, while potentially reusing power plant assets such as transmission and other facilities, switching to more economic fuel types, or uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be economically operated and maintained or meet environmental requirements will reduce the existing generation.

Impact of EPA Rules

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, the six EPA rules identified below were anticipated to affect electric generation in Florida. The first five rules are currently under EPA review pursuant to Executive Order 13990. [8] Future developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units - Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule is currently under appeal. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. However, no final regulatory actions have been taken. Future developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units: On July 8, 2019, EPA finalized the ACE rule. ACE establishes carbon emission guidelines such that each state must perform site-specific reviews to determine the applicable standard of performance using the EPA's best system of emission reduction (BSER). The BSER identifies six technologies upgrades as well as operation and maintenance practices directed at improving the heat rate efficiency of coal-fired steam generating units greater than 25 MWs that began construction on or before January 8, 2014. No other type of existing fossil steam utility generators are subject to the requirements of ACE. However, on January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it to the EPA. As the Court did not expressly reinstate the CPP, the EPA understands the decision as leaving neither of those rules, and thus no CAA section 111(d) regulation, in place with respect to greenhouse gas emissions from electric generating units.

- Prevention of Significant Deterioration and Nonattachment New Source Review: On August 1, 2019, the EPA announced a proposed rule that would revise certain New Source

[8] See Executive Order 13990 Fact Sheet.

Review (NSR) applicability regulation to clarify the requirements that apply to new sources, such as electric steam generators, proposing to undertake a physical or operational change (i.e., project) under the NSR preconstruction permitting program. EPA is proposing to clarify that both emission increases and decreases resulting from a given project are to be considered when determining whether the project by itself results in a significant emission increase.

- Mercury and Air Toxics Standards (MATS) - Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.

- Cooling Water Intake Structures (CWIS) - Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating facilities. All electric generators that use state or federal waters for cooling with an intake velocity of at least two million gallons per day must meet impingement standards. Generating units with higher intake velocity may have additional requirements to reduce the damage to aquatic wildlife due to entrapment in the cooling water system.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on landfills in which coal ash is deposited. On July 29, 2020, the EPA issued for publication in the Federal Register, a final rule that will require among other things that unlined impoundments and CCR units that failed to meet ground water quality regulations must cease receipt of waste streams by April 11, 2021.

Each utility will need to evaluate whether these additional costs or operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action.

Modernization and Efficiency Improvements

Modernizations involve removing existing generator units that may no longer be economical to operate, such as oil-fired steam units, and reusing the power plant site's transmission or fuel handling facilities with a new set of generating units. The modernization of existing plant sites, allows for significant improvement in both performance and emissions, typically at a lower price than new construction at a greenfield site. Not all sites are candidates for modernization due to site layout and other concerns, and to minimize rate impacts, modernization of existing units should be considered along with new construction at greenfield sites.

The Commission has previously granted determinations of need for several conversions of oil-fired steam units to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades power plants. DEF has also conducted a conversion of its Bartow power plant, but this did not require a determination of need from the Commission.

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. TECO is modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by 2023. Per the Florida Department of Environmental Protection, this conversion does not require a determination of need by the Commission. FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants.

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 8 lists the 5,385 MW of existing generation that is scheduled to be retired during the planning period. Within the next 10 years, 12 natural gas units totaling 2,878 MW, 7 coal units totaling 2,152 MW, and 12 oil units totaling 534 MW are scheduled to retire.

Table 8: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)
				Summer
2021	FPL/GPC	Manatee 1 & 2	NG – ST	1,618
	FPL/GPC	Scherer 4	BIT – ST	634
	TECO	Big Bend 2	NG – ST	446
	LAK	McIntosh Unit No. 3	BIT-ST	205
			2021 Subtotal	**2,903**
2022	GRU	Deerhaven FS01	NG – ST	75
	SEC	Seminole Generating Station 1 or 2*	BIT – ST	736
			2022 Subtotal	**811**
2023	TECO	Big Bend 3	NG – ST	395
			2023 Subtotal	**395**
2024	FPL/GPC	Crist 4	BIT – ST	75
	FPL/GPC	Daniel 1 & 2	BIT – ST	502
			2024 Subtotal	**577**
2025	DEF	Bayboro P1 – P4	DFO – CT	171
	FPL/GPC	Pea Ridge 1 - 3	NG – CT	12
			2025 Subtotal	**183**
2026	GRU	Deerhaven GT01 & GT02	NG – CT	35
	FPL/GPC	Crist 5	BIT – ST	75
			2026 Subtotal	**110**
2027	DEF	Debary P2 – P6	DFO – CT	249
	DEF	University of Florida P1	NG – CT	43
	DEF	Bartow P1 & P3	DFO – CT	82
	FPL/GPC	Lansing Smith A	DFO – CT	32
			2027 Subtotal	**406**
			Total Retirements	**5,385**

* SEC has not determined whether to retire SGS 1 (626 MW) or SGS 2 (634 MW) at this time.

Source: 2021 Ten-Year Site Plans

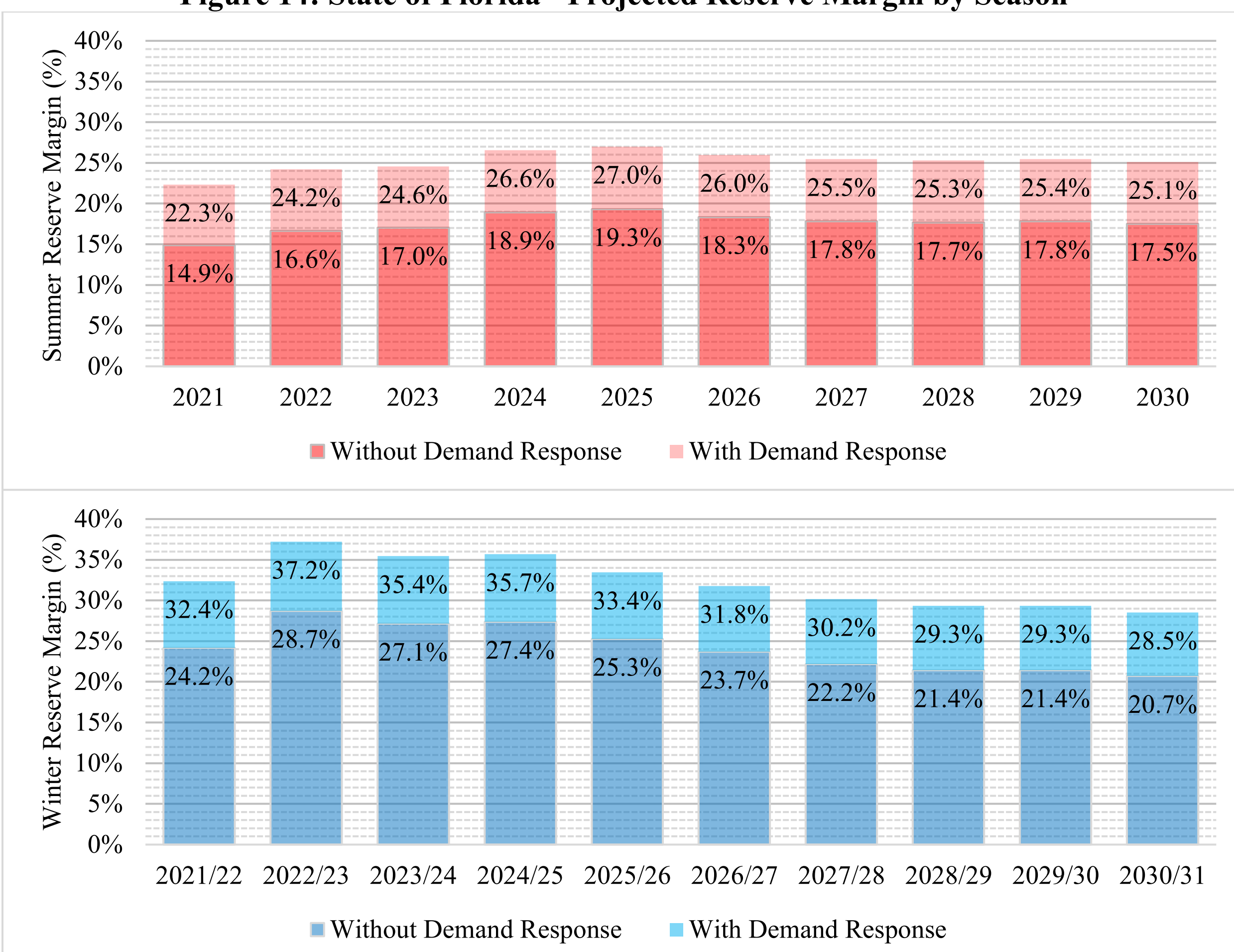
Reliability Requirements

Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted customer demand. If utilities only had sufficient generating capacity to meet forecasted peak demand, then potential instabilities could occur if customer demand exceeds the forecast, or if generating units are unavailable due to maintenance or forced outages. To address these circumstances, utilities are required to maintain additional planned generating capacity above the forecast customer demand, referred to as the reserve margin.

On July 1, 2019, the SERC Reliability Corporation (SERC) became the new Compliance Enforcement Authority for all electric utilities previously registered with the FRCC. Electric utilities within Florida must maintain a minimum reserve margin of 15 percent for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

While Florida's electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 14 is a projection of the statewide seasonal reserve margin including all proposed power plants.

Figure 14: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2021Regional Load and Resource Plan

Role of Demand Response in Reserve Margin

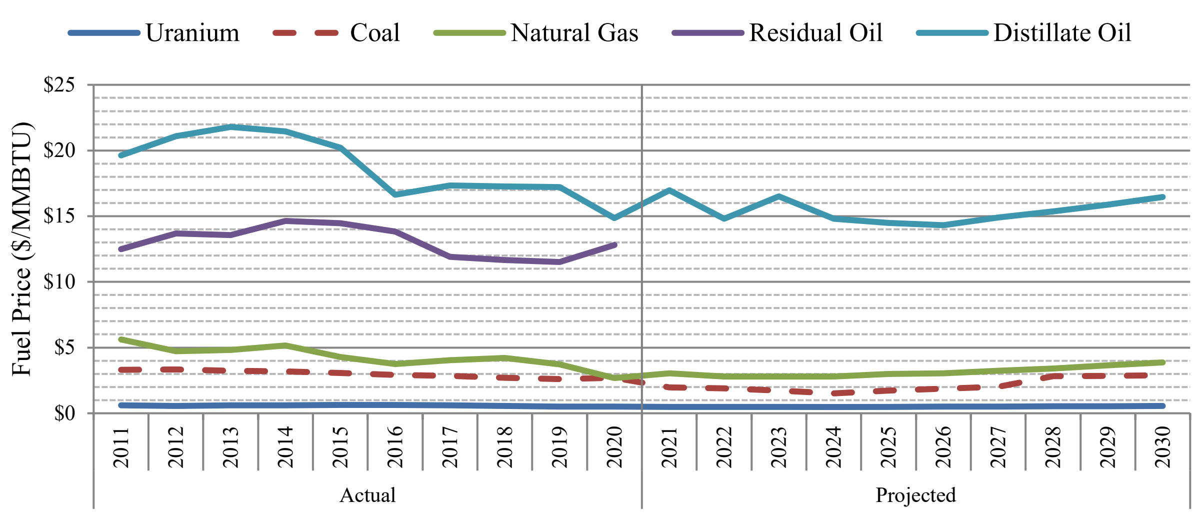
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 14, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.6 percent on average.

Demand response participants receive discounted rates or credits regardless of activation, with these costs recovered from all ratepayers. Because of the voluntary nature of demand response, a concern exists that a heavy reliance upon this resource would make participants eschew the discounted rates or credits for firm service. For interruptible customers, participants must provide notice that they intend to leave the demand response program, with a notice period of three or more years being typical. For load management participants, usually residential or small commercial customers, no advanced notice is typically required to leave. Historically, demand response participants have rarely been called upon during the peak hour, but are more frequently called upon during off-peak periods due to unusual weather conditions.

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a fuel-based power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, and uranium. Distillate oil and residual oil also factor into Florida utilities' fuel mix, albeit minimally when compared to historical levels. Distillate oil remains the most expensive fuel, which explains why it is used for backup and peaking purposes only, while residual oil is being phased out, with none of the TYSP Utilities forecasting the price of residual oil after 2021. Figure 15 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

Figure 15: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities



Source: Utilities Responses to FPSC Staff's Data Requests

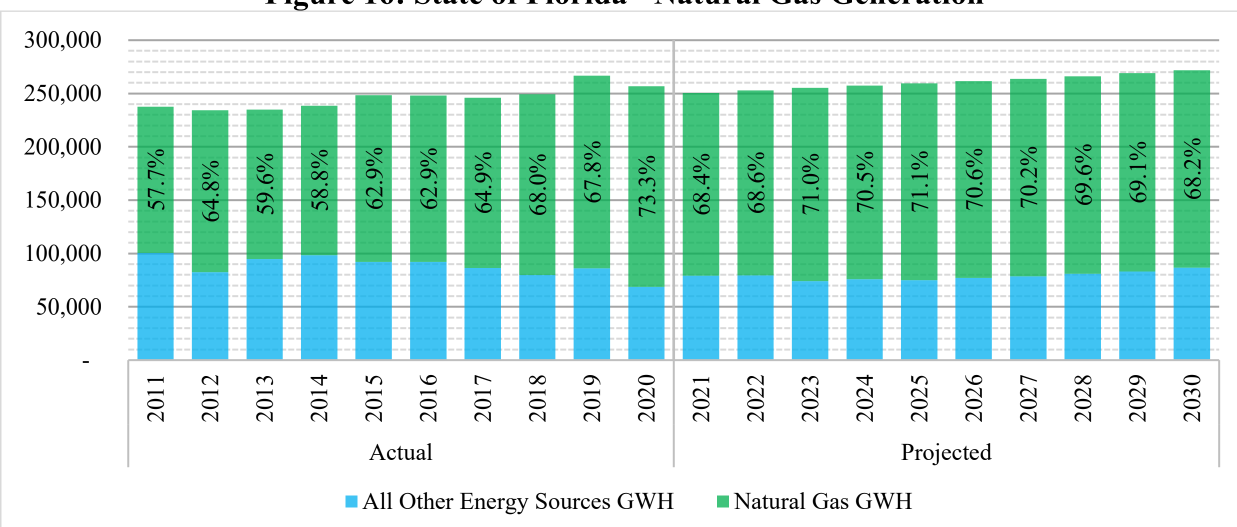
As shown in Figure 15, the price of natural gas continued to decline from 2012 until 2020. Even though current forecasts project the price of natural gas to remain relatively stable over the long term, there remains some degree of natural gas price volatility over the short and medium term. For instance, natural gas price volatility was reflected in the 2021 requests for fuel factor mid-course corrections (increases in customer fuel charges) filed by TECO and DEF, and approved by the PSC on August 3, 2021.[9]

The price of coal has been stable from 2012 through 2020. However, forecasts show a slight decrease through 2024 at which time coal prices are forecasted to nearly double by 2030. It should be noted that Florida utilities' reliance on coal for electric generation is projected to decrease substantially over the next 10 years.

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida and since 2011 has generated more net energy for load than all other fuels combined. As Figure 16 illustrates, natural gas was the source of approximately 73 percent of electric energy consumed in Florida in 2020. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline slightly throughout the remainder of the planning period.

Figure 16: State of Florida - Natural Gas Generation



Source: FRCC 2012-2021 Regional Load and Resource Plan

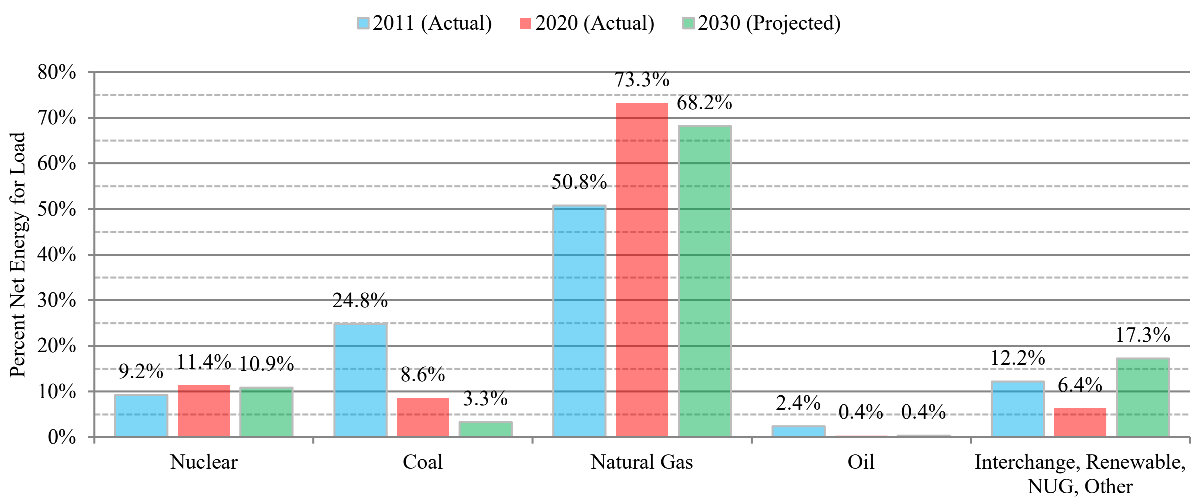
Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatility in fuel price fluctuations, it is important that utilities have a level of flexibility in their generation mix. Maintaining fuel diversity on Florida's system faces several difficulties. Existing coal units will require additional emissions control equipment leading to reduced output, or retirement if the emissions controls are uneconomic to install or operate. New solid fuel generating units such as

[9] Docket No. 20210001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.* .

nuclear and coal have long lead times and high capital costs. New coal units face challenges relating to new environmental compliance requirements, making it unlikely they could be permitted without novel emissions control technology.

Figure 17 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2011 and 2020, and forecast year 2030. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period.

Figure 17: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2012-2021 Regional Load and Resource Plan

Based on 2018 Energy Information Administration (EIA) data, Florida ranks fourth in terms of the total volume of natural gas consumed compared to the rest of the United States.[10] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

New Generation Planned

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity is expected to increase, making the addition of

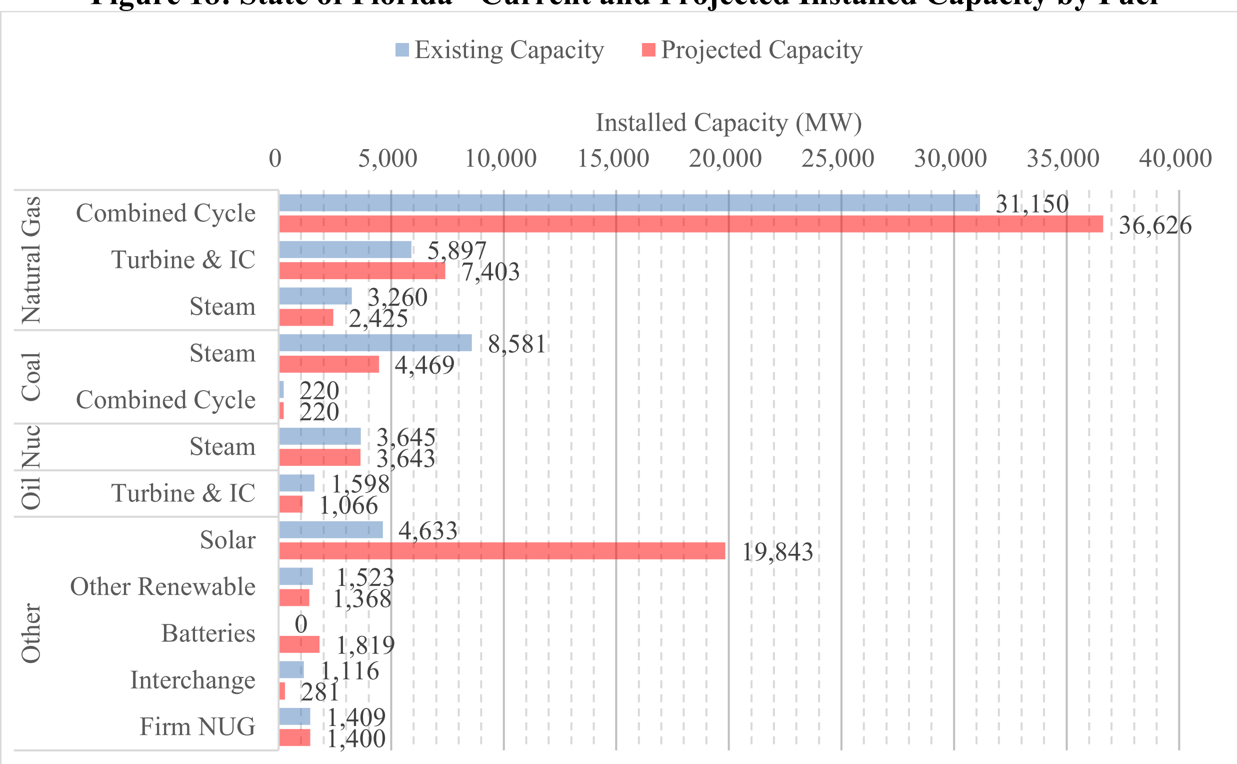
[10] U.S. Energy Information Administration natural gas consumption by end-use annual report.

traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.

In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

Figure 18 illustrates the present and future aggregate capacity mix. The capacity values in Figure 18 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2021 Ten-Year Site Plans and the FRCC's 2021 Regional Load and Resource Plan. Unlike previous years, capacity contributions from non-utility generators have now been included in their respective fuel and generation technology categories, as opposed to reported separately, to better represent the aggregate existing and projected capacity in Florida.

Figure 18: State of Florida - Current and Projected Installed Capacity by Fuel



Source: FRCC 2021 Regional Load and Resource Plan & TYSP Utilities' Data Responses

New Power Plants by Fuel Type

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. In April of 2018, FPL received Combined Operating Licenses (COL) from the Nuclear Regulatory Commission (NRC) for two future nuclear units, Turkey Point Units 6 & 7. These units are planned to be sited at FPL's Turkey Point site, the location of two existing nuclear generating units. The earliest possible in service date for these two units are outside the scope of the Ten-Year Site Plan. FPL has two nuclear projects at Turkey Point that have minimal uprates planned during the projection period. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013.

Natural Gas

Several new natural gas-fired combustion turbines, internal combustion units, and combined cycle units are planned over the next 10 years. Combustion turbines that run only in simple cycle mode and internal combustion units, taken together, represent the third most abundant type of generating capacity. As combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 9 summarizes the approximately 5,454 MW of additional capacity from new natural gas-fired generating units proposed by the 2021 Ten-Year Site Plan utilities.

Several utilities are exploring the use of natural gas internal combustion units (also called reciprocating engines) as a means of fast ramping peaking capacity. Such additions afford improved environmental and reliability benefits, enhanced operational flexibility, and improvements to system resiliency.

Table 9: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW)	Notes
Previously Approved New Units				
2022	FPL	Dania Beach Energy Center	1,163	Docket No. 20170225-EI
	SEC	Seminole CC Facility	1,099	Docket No. 20170266-EI
2025	SEC	Unnamed CC	542	Docket No. 20170266-EI
			Subtotal	**2,804**
New Units Requiring PPSA Approval				
None				
			Subtotal	**0**
New Units Not Requiring PPSA Approval				
2023	TECO	Big Bend CC Conversion	1,055	Includes Big Bend 1 Steam Turbine
2022	FPL	Crist Unit 8	938	4 Combustion Turbines
2024	LAK	Mcintosh IC3-7	100	5 Reciprocating Engines
2024	TECO	Reciprocating Engine	37	2 Reciprocating Engines
2027	DEF	Unsited Combustion Turbine	214	
2029	DEF	Unsited Combustion Turbine	214	
2030	SEC	Unnamed Reciprocating Unit	92	
			Subtotal	**2,650**
			Total	**5,454**

Source: 2021 Ten-Year Site Plans

Commission's Authority Over Siting

Any proposed steam or solar generating unit greater than 75 MW requires a certification under the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has been given exclusive jurisdiction to determine the need for new electric power plants through Section 403.519, F.S. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. There are no new units in the 10 year horizon that require certification under the PPSA.

Transmission

As generation capacity increases, the transmission system must grow accordingly to maintain the capability of delivering energy to end-users. The Commission has been given broad authority pursuant to Chapter 366, F.S., to require reliability within Florida's coordinated electric grid and to ensure the planning, development, and maintenance of adequate generation, transmission, and distribution facilities within the state.

The Commission has authority over certain proposed transmission lines under the Electric Transmission Line Siting Act (TLSA), contained in Sections 403.52 through 403.5365, F.S. To require certification under Florida's TLSA, a proposed transmission line must meet the following criteria: a nominal voltage rating of at least 230 kV, crossing a county line, and a length of at least 15 miles. Proposed lines in an existing corridor are also exempt from TLSA requirements. The Commission determines the reliability need and the proposed starting and end points for lines requiring TLSA certification. The proposed corridor route is subsequently determined by the Florida Department of Environmental Protection during the certification process. Much like the PPSA, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of a proposed line.

Table 10 lists all proposed transmission lines in the 2021 Ten-Year Site Plans and the FRCC 2021 Regional Load and Resource Plan that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

Table 10: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Levee to Midway	150	500	5/28/1988	4/20/1990	2030
TECO	Thonotosassa to Wheeler	8	230	6/22/2007	8/8/2008	TBD
TECO	Wheeler to Willow Oak	17	230	6/23/2006	8/9/2008	TBD
TECO	Lake Agnes to Gifford	27.5	230	9/26/2007	2/18/2009	TBD

Source: 2021 Ten-Year Site Plans & FRCC 2021 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL) & Gulf Power Company (GPC)

FPL and GPC are the largest and smallest generating investor-owned utilities, respectively, and are Florida's first and sixth largest electric utilities. FPL's service territory is within the FRCC region and is primarily in south Florida and along the east coast, while GPC's service territory is within the Florida Panhandle region. NextEra Energy Inc., FPL's parent company acquired GPC through a purchase that closed during the first half of 2019. The companies filed a joint Ten-Year Site Plan that outlined the planning for both companies separately until January 1, 2022, and the completion of an interconnecting transmission line, after which GPC and FPL would merge from an operational perspective, at which point GPC will be operated entirely by FPL. Prior to the final operational merger, some of GPC will continue to be operated in conjunction with other Southern Company utilities. As such, not all of the energy generated by GPC will be consumed within Florida. As both are investor-owned utilities, the Commission has regulatory authority over all aspects of their operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL and GPC's joint 2021 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2020, FPL had approximately 5,136,995 customers and annual retail energy sales of 113,531 GWh, or approximately 48.8 percent of Florida's annual retail energy sales. FPL's total customers grew 1.5 percent in 2020. The utility noted that the 2020 customer growth is more indicative of normal growth rates when compared to the 2019 customer growth rate (2.0 percent), which was higher due to the acquisition of Vero Beach at the end of 2018. FPL's weather-normalized retail energy sales increased 0.6 percent in 2020. This increase is primarily attributable to the growth in the residential class, and partially offset by declines in the commercial class. Residential energy sales grew due to higher usage and customer growth while commercial energy sales declined due to lower usage, partially offset by customer growth. Figure 19 illustrates FPL's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the past 10 years, FPL's customer base has increased by 12.97 percent, while retail sales have grown by 9.87 percent.

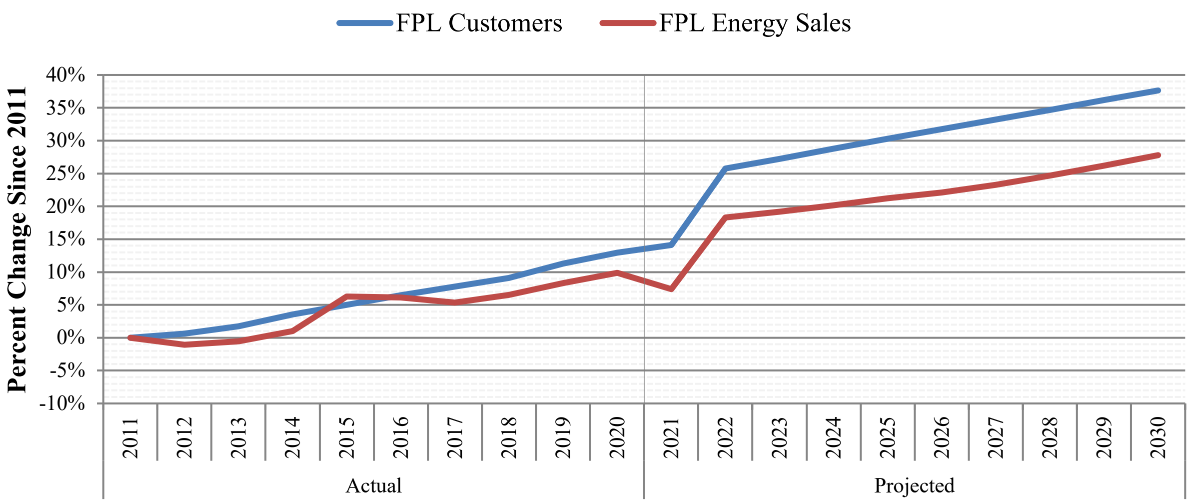
In 2020, GPC had approximately 470,680 customers and annual retail energy sales of 10,635 GWh, or approximately 4.6 percent of Florida's annual retail energy sales. GPC's total customers grew by 1.2 percent in 2020, compared to flat growth in 2019 which was due to the impacts of Hurricane Michael. GPC's weather-normalized retail energy sales decreased by 1.9 percent in 2020 due to lower commercial and industrial energy sales, partially offset by higher residential sales. Figure 19 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales from 2011 to 2022, at which point GPC's growth is integrated into FPL's forecasts to reflect system integration. Over the last 10 years, GPC's customer base has increased by 8.85 percent, while retail sales have decreased by 3.67 percent.

For both FPL and GPC, weather-normalized use per customer for residential and commercial customers was significantly affected by the COVID-19 Pandemic and the shelter-in-place orders that were implemented to mitigate the spread of the virus. The results were an increase in residential usage by 3.8 percent and 1.2 percent for FPL and GPC, respectively, due to people staying at home more. On the other hand, FPL and GPC experienced a decrease in commercial usage of 6.4 percent and 6.8 percent, respectively, due to business shutdowns. FPL's industrial use per customer increased in 2020 which the utility indicated is not attributable to impacts from the COVID-19 Pandemic. GPC's weather-normalized industrial per customer usage decreased 5.3 percent in 2020 due to lower usage by a small number of large industrial customers.

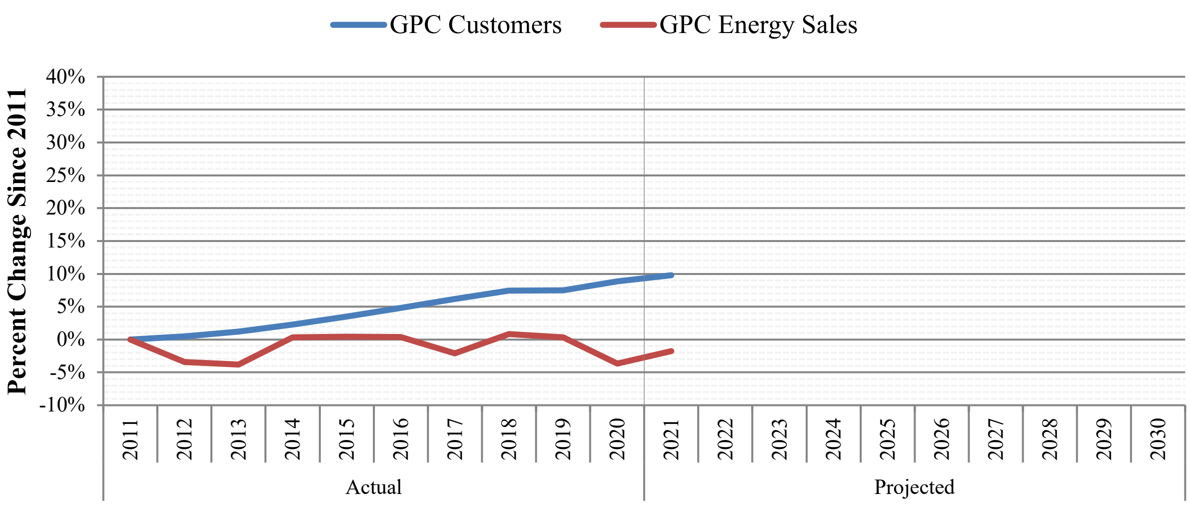
In the utilities' 2021 Ten-Year Site Plan, customers for the combined FPL and Gulf system are forecasted to grow by 1.1 to 1.2 percent per year, with total customer growth being driven primarily by residential customer growth. Retail sales of the FPL and GPC combined system are forecasted to grow by 0.7 to 1.3 percent per year over the forecast horizon. This is driven by growth in residential and commercial class sales attributed to customer growth, partially offset by usage declines related to improvements in electric appliance efficiencies.

Figure 19: FPL & GPC Growth

FPL



GPC



Source: 2021 Ten-Year Site Plan

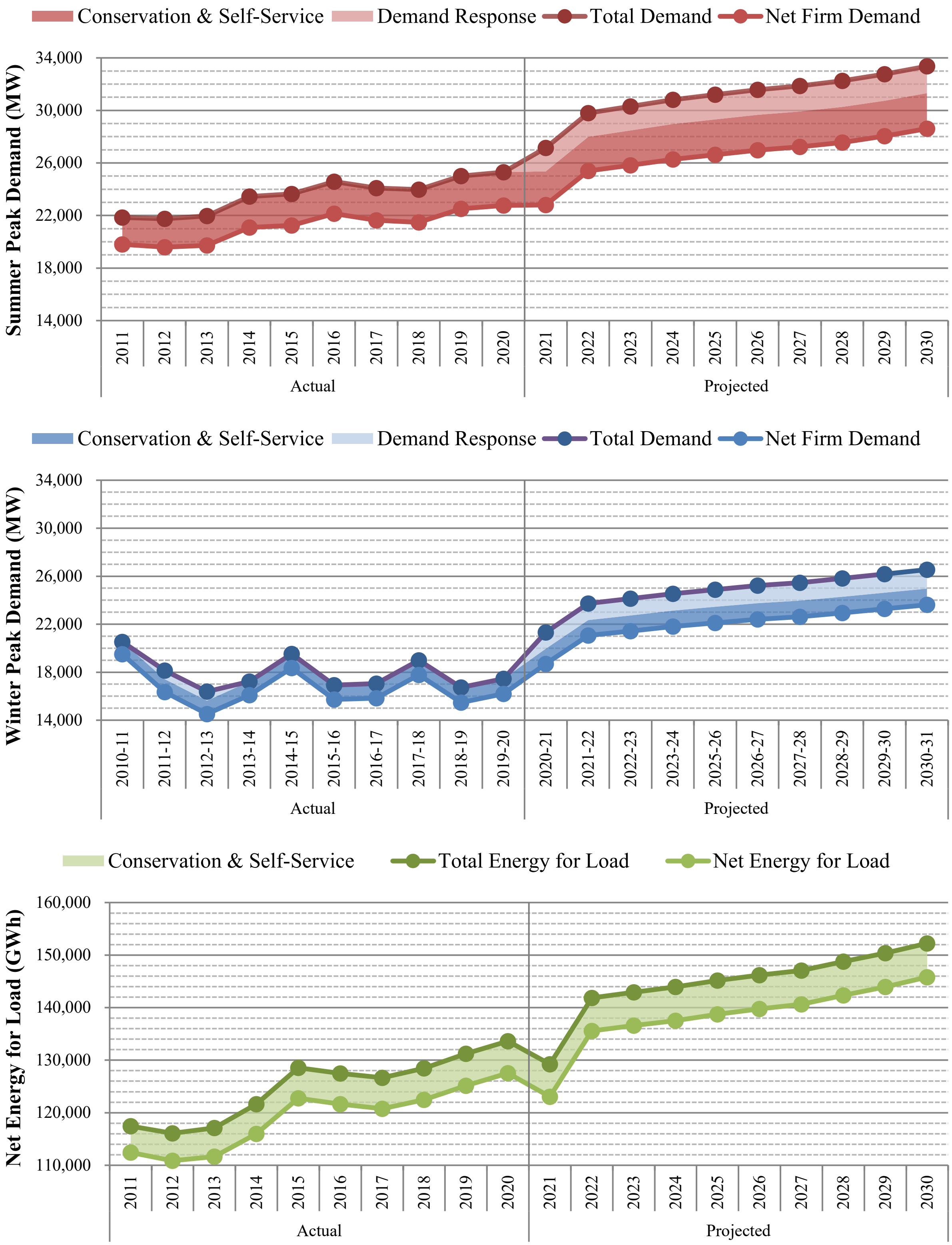
As mentioned earlier, on January 1, 2019, GPC became a subsidiary of NextEra, FPL's parent company. FPL and GPC plan to integrate the two systems into a single electric system, effective January 1, 2022. Consistent with last year's report, the demand and energy forecasts for FPL and GPC continue to be presented separately for the year 2021. For years 2022 through 2030, the demand and energy forecasts for FPL/GPC are presented as a single integrated utility (FPL), as depicted in Figure 20.

The three graphs in Figure 20 show FPL's seasonal peak demand and net energy for load, for the historic years 2011 through 2020 and forecast years 2021 through 2030. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. FPL expects a spike in all demand and energy forecasts in 2022 due to its planned integration with GPC's system. Historically, demand response has not been activated during the seasonal peak demand, excluding the winter of 2010-11.

The three graphs in Figure 21 show GPC's seasonal peak demand and net energy for load, for the historic years 2011 through 2020 and forecast year 2021. GPC's demand and energy forecasts sharply decline to zero after 2021 due to the utility's planned integration with FPL's system.

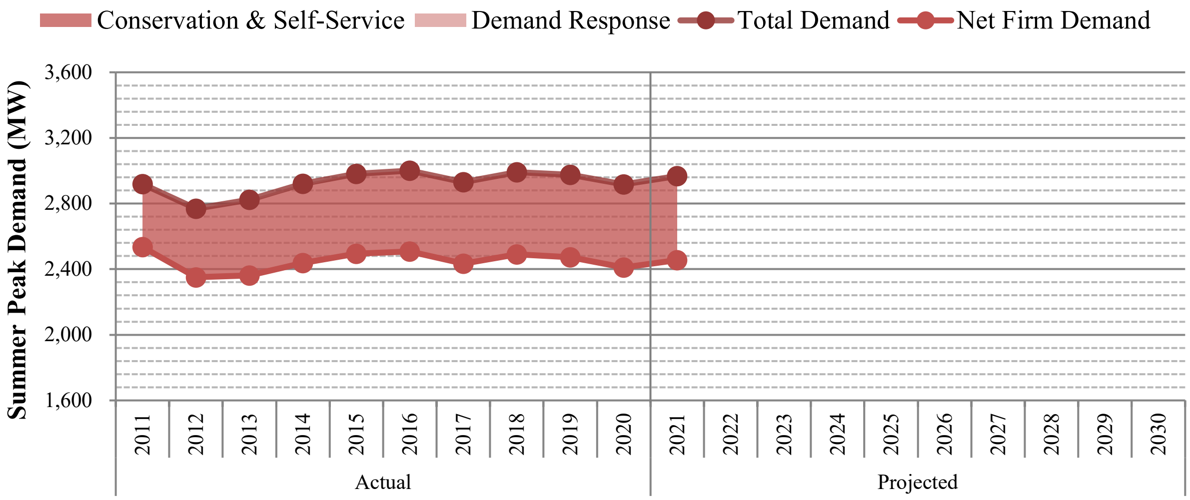
As investor-owned utilities, FPL and GPC are subject to FEECA and currently offer energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024.

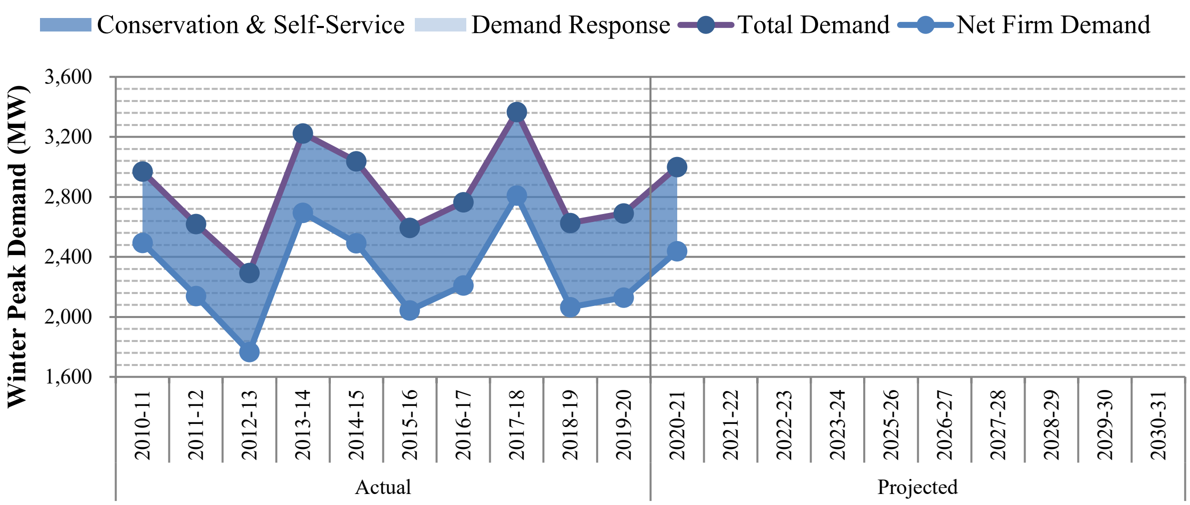
Figure 20: FPL Demand and Energy Forecasts

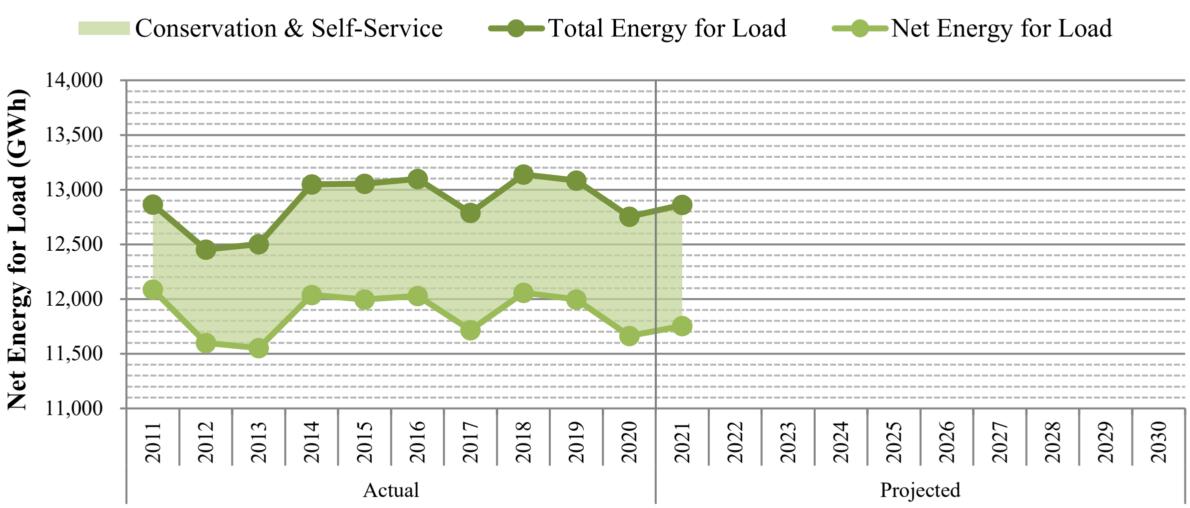


Source: 2021 Ten-Year Site Plan and Data Responses

Figure 21: GPC Demand and Energy Forecasts







Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 11 shows FPL's and GPC's actual net energy for load by fuel type for 2020, and the projected fuel mix for the combined companies for 2030. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 75 percent of net energy for load in 2020. GPC was an energy exporter in 2020, producing approximately 22 percent more energy than it required for native load. While natural gas was the dominant fuel source in 2020, nuclear was the second most utilized fuel source. FPL projects that renewable energy will provide over 18 percent of its generation by 2030, which is the second highest percentage of renewable energy generation in 2030 of the TYSP Utilities.

Table 11: FPL and GPC Energy Generation by Fuel Type

Fuel Type	Net Energy for Load					
	FPL		GPC		FPL	
	2020		2020		2030	
	GWh	%	GWh	%	GWh	%
Natural Gas	95,278	**74.7%**	10,474	**89.8%**	89,672	**61.4%**
Coal	1,636	**1.3%**	2,067	**17.7%**	238	**0.2%**
Nuclear	28,221	**22.1%**	0	**0.0%**	28,421	**19.5%**
Oil	119	**0.1%**	0	**0.0%**	4	**0.0%**
Renewable	3,785	**3.0%**	1,423	**12.2%**	26,638	**18.2%**
Interchange	0	**0.0%**	-2,671	**-22.9%**	0	**0.0%**
Other	(1,519)	**-1.2%**	372	**3.2%**	1,147	**0.8%**
Total	**127,519**		**11,665**		**146,119**	

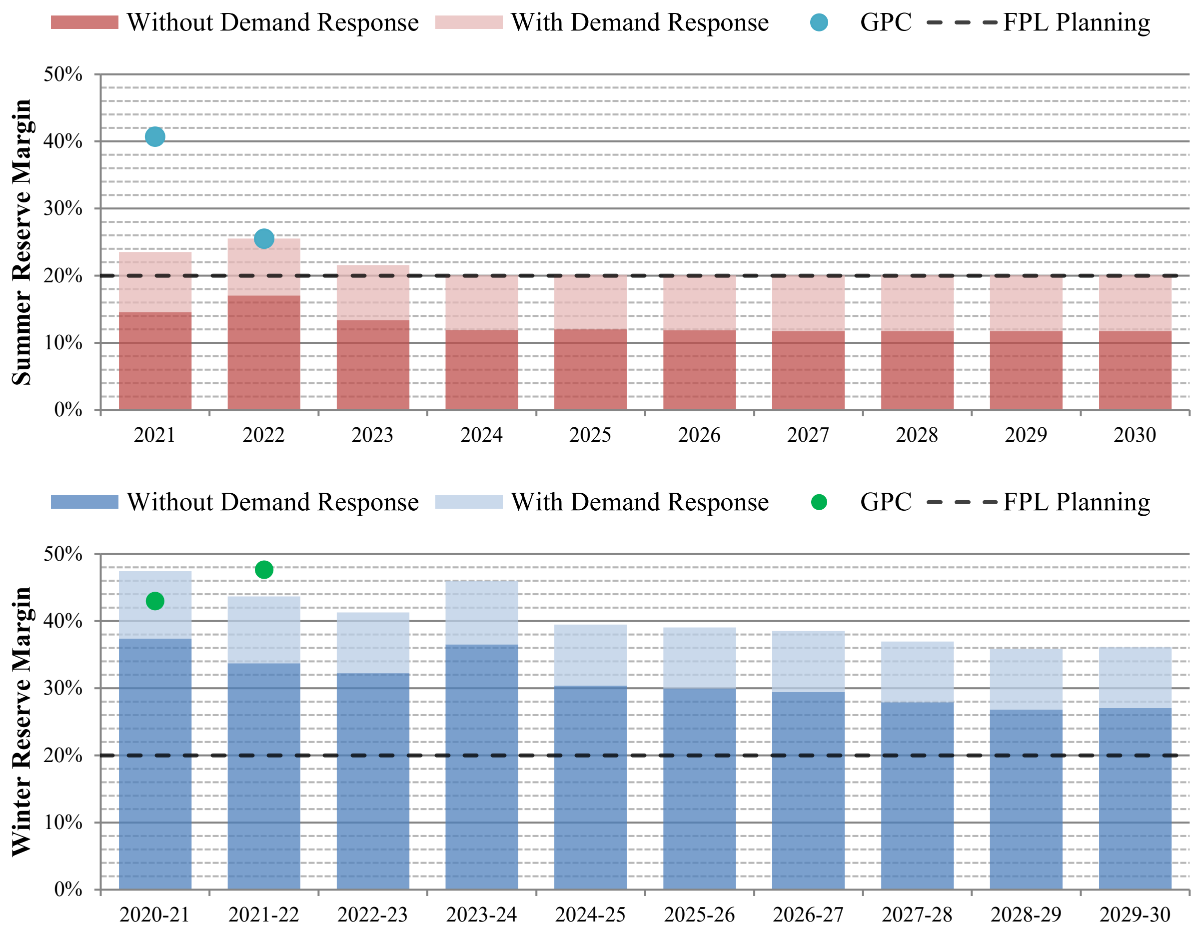
Source: 2021 Ten-Year Site Plan

Reliability Requirements

While previously only reserve margin has been discussed, Florida's utilities use multiple indices to determine the reliability of its electric supply. An additional metric is the Loss of Load Probability (LOLP), which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. FPL uses a maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity.

Since 1999, FPL has utilized a 20 percent reserve margin criterion for planning based on a stipulation approved by the Commission, while GPC did not have an explicit planning reserve margin criteria for 2020 through 2021. Figure 22 displays the forecast planning reserve margin for GPC (through 2021) and FPL through the planning period for both seasons, with and without the use of demand response. As shown in the figure, FPL's generation needs are controlled by its summer peak throughout the planning period.

Figure 22: FPL and GPC Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion which it refers to as its 10 percent generation-only reserve margin. This criterion requires that available firm capacity be 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. Currently, no other utility utilizes this same metric. FPL's generation-only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

While FPL does not include incremental energy efficiency resources and cumulative demand response in its resource planning for the generation-only reserve margin criterion, the utility would remain subject to FEECA and the conservation goals established by the Commission. FPL would continue paying rebates and other incentives to participants, which are collected from all ratepayers through the Energy Conservation Cost Recovery Clause, but would not consider the potential capacity reductions of any future participation in energy efficiency or demand response programs during the 10-year planning period for planning purposes only when using this reliability criterion.

Energy efficiency, which includes installation of equipment designed to reduce peak demand and annual energy consumption, is considered a passive resource. While demand response must be activated by the utility, energy efficiency provides benefits consistently for the duration of the installation, reducing annual energy consumption, and if usage is coincident with system peak, peak demand. Customers do not remove building envelope improvements or newly installed equipment until the end of its service life for replacement.

As noted in the Statewide Perspective, the Commission does review the impact on reserve margin of demand response resources. At this time, FPL offers two types of demand response programs. The first type is interruptible and curtailable load programs, consisting of the Commercial/Industrial Load Control Program (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) tariffs. The second type is load management programs, including the Residential On-Call and Business On-Call Programs. FPL utilizes load management programs on residential customers more often than commercial/industrial customers. GPC also has utilized demand response as a way of meeting reserve margin requirements through two types of demand response programs. The first type a curtailable load through the Commercial Curtailable Load Program, and time of use rates. The second type is automated energy monitoring through its Energy Select Program, which helps customers monitor and control energy consumption.

Generation Resources

Both FPL and GPC plan multiple unit retirements and additions during the planning period. These changes are as described in Table 12 for the FPL region and Table 13 for the GPC region. A combined total of 1,287 MW of coal generation is being retired, between FPL's partial ownership of Scherer 4 (634 MW) and GPC's Daniel 1 & 2 (502 MW) and Crist 4 & 5 (156 MW). FPL also plans to retire the natural gas-fired steam units Manatee 1 & 2 in 2021 due to the significant annual capital and operation and maintenance (O&M) costs required to keep these relatively fuel-inefficient units operational. FPL also plans to retire four smaller oil and gas CT units with a total capacity of 44 MW over the planning period from the GPC territory.

Regarding additions, before the interconnection with FPL, GPC plans four natural gas-fired CTs, Crist 8, for a total of 938 MW in 2021. FPL's Dania Beach Clean Energy Center, a natural gas-fired combined cycle unit, which was grant a determination of need on March 19, 2018 and is expected to be in-service by 2022. The projected in-service dates of FPL's planned nuclear units are outside the 10-year planning period.

FPL and GPC also plan to add approximately 9,300 MW of solar photovoltaic plants over the planning period. These include approximately 1,490 MW from the SolarTogether Program, which was approved by the Commission in March 2020. Approximately 7,600 MW of solar is planned for the FPL region and 1,700 MW for the GPC region. Solar makes up approximately 80 percent of FPL's and GPC's planned future units. The values above do not reflect the proposed settlement agreement in FPL's base rate case, Docket No. 20210015-EI, which included an additional expansion of the SolarTogether program. If approved, the expansion would be reflected in next year's Ten-Year Site Plan.

FPL and GPC anticipate adding a total of 1,169 MW of battery storage over the planning period. FPL's 469 MW battery storage project is planned for 2022, of which 409 MW will be placed in service in Manatee County to offset the retirement of Manatee 1 & 2. FPL has plans for three more battery projects totaling 700 MW. The batteries being deployed in these projects will expand the number of storage applications and configurations that FPL will be able to test, as well as making the scale of deployment more meaningful, given the large size of FPL's system.

Table 12: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (MW) Sum	Notes
Retiring Units					
2021	Manatee 1 & 2	NG – ST	1,626	N/A	
2021	Scherer 4	BIT- ST	634	N/A	
Total Retirements			**2,260**		
New Units					
2021	Pelican Solar	PV	75	36	Docket No. 20190061-EI
2021	Magnolia Springs	PV	75	36	
2021	Rodeo Solar	PV	75	36	
2021	Discovery Solar	PV	75	36	
2021	Willow Solar	PV	75	36	
2021	Orange Blossom Solar	PV	75	36	
2021	Palm Bay Solar	PV	75	36	
2021	Fort Drum Solar	PV	75	36	
2021	Sabal Palm Solar	PV	75	36	
2022	Manatee Energy Storage	BAT	409	N/A	
2022	Sunshine Gateway Energy Storage	BAT	30	N/A	
2022	Echo River Energy Storage	BAT	30	N/A	
2022	Dania Beach Clean Energy Center	NG – CC	1,163	N/A	Docket No. 20170225-EI
2022	Ghost Orchid Solar	PV	75	39	
2022	Sawgrass Solar	PV	75	39	
2022	Sundew Solar	PV	75	39	
2022	Immokalee Solar	PV	75	39	
2022	Grove Solar	PV	75	39	
2022	Elder Branch Solar	PV	75	39	
2023	Everglades Solar	PV	75	30	
2023	Whitetail Solar	PV	75	30	
2023	Bluefield Preserve Solar	PV	75	30	
2023	Cavendish Solar	PV	75	30	
2023	Anhinga Solar	PV	75	30	
2024	Unknown Solar	PV	522	263	
2025	Unknown Solar	PV	522	263	
2026	Unknown Solar	PV	894	370	
2027	Unknown Solar	PV	969	396	
2028	Unknown Solar	PV	1,192	473	
2029	Unknown Solar	PV	1,043	224	
2029	Unsited Battery Storage	BAT	300	N/A	
2030	Unknown Solar	PV	968	198	
2030	Unsited Battery Storage	BAT	100	N/A	
Total New Units			**9,642**	**2,895**	
Net Additions			**7,382**		

Source: 2021Ten-Year Site Plan

Table 13: GPC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (MW) Sum	Notes
Retiring Units					
2024	Daniel 1 & 2	BIT - ST	502	N/A	
2024	Crist 4	BIT – ST	78	N/A	
2025	Pea Ridge 1 – 3	NG – CT	12	N/A	
2026	Crist 5	BIT – ST	78	N/A	
2027	Lansing Smith A	DFO – CT	32	N/A	
Total Retirements			**702**		
New Units					
2022	Crist 8	NG - CT	938	N/A	4 Combustion Turbines
2022	Blue Springs Solar	PV	75	41	
2022	Cotton Creek	PV	75	43	
2023	Blackwater Solar	PV	75	37	
2023	Chipola Solar	PV	75	37	
2023	Flowers Creek Solar	PV	75	37	
2023	First City Solar	PV	75	37	
2023	Apalachee Solar	PV	75	37	
2024	Unknown Solar	PV	373	171	
2025	Unknown Solar	PV	373	171	
2026	Unknown Solar	PV	75	34	
2029	Unknown Solar	PV	149	60	
2030	Unknown Solar	PV	224	90	
2030	Unsited Battery Storage	BAT	300	N/A	
Total New Units			**2,019**	**795**	
Net Additions			**1,317**		

Source: 2021 Ten-Year Site Plan

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The utility's service territory is within the FRCC region and is primarily in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

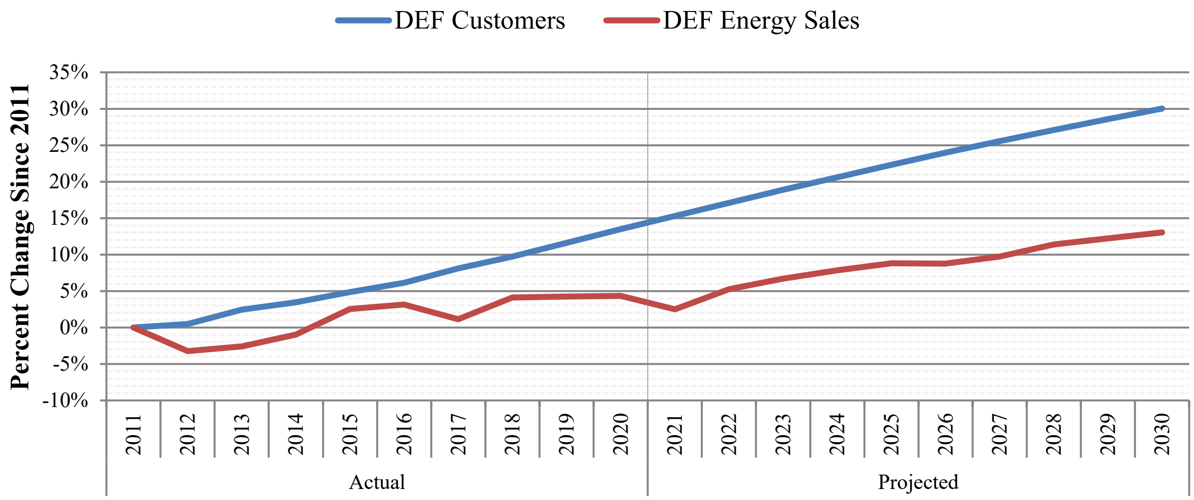
In 2020, DEF had approximately 1,863,814 customers and annual retail energy sales of 39,230 GWh or approximately 16.9 percent of Florida's annual retail energy sales. DEF's total customers grew 1.69 percent approximately in 2020. Figure 23 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, DEF's customer base has increased by 13.50 percent, while retail sales have grown by 4.34 percent.

DEF's customer growth has always been dominated by the Residential and Commercial customer classes. Customer growth trends are driven by broad economic and demographic factors such as population growth, migration, retirement, affordable housing, mortgage rates and job growth. More recent information reflects a return to the long-term trend of population migration into Florida. Commercial customer growth typically tracks residential growth supplying needed services.

As indicated previously in the Statewide Perspective section of this Report, the projected retail energy sales trend reflects the product of the utilities' forecasted number of customers and forecasted energy consumption per customer. Per customer usage for DEF's residential and commercial classes are primarily driven by fluctuations in electricity price, end use appliance saturation and efficiency improvement, housing type/building size, improved building codes, and space conditioning equipment fuel type. With respect to the average KWh consumption per customer, the utility is aware that the ability to self-generate recently has begun to make more of an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generation, reducing consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind their meter. The utility also noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal.

For the 2021 10-year forecast horizon, DEF's forecast results indicate that the utility's customer base are projected to grow at an average annual rate of 1.35 percent, and its retail energy sales are projected to grow at a average annual rate of 1.10 percent.

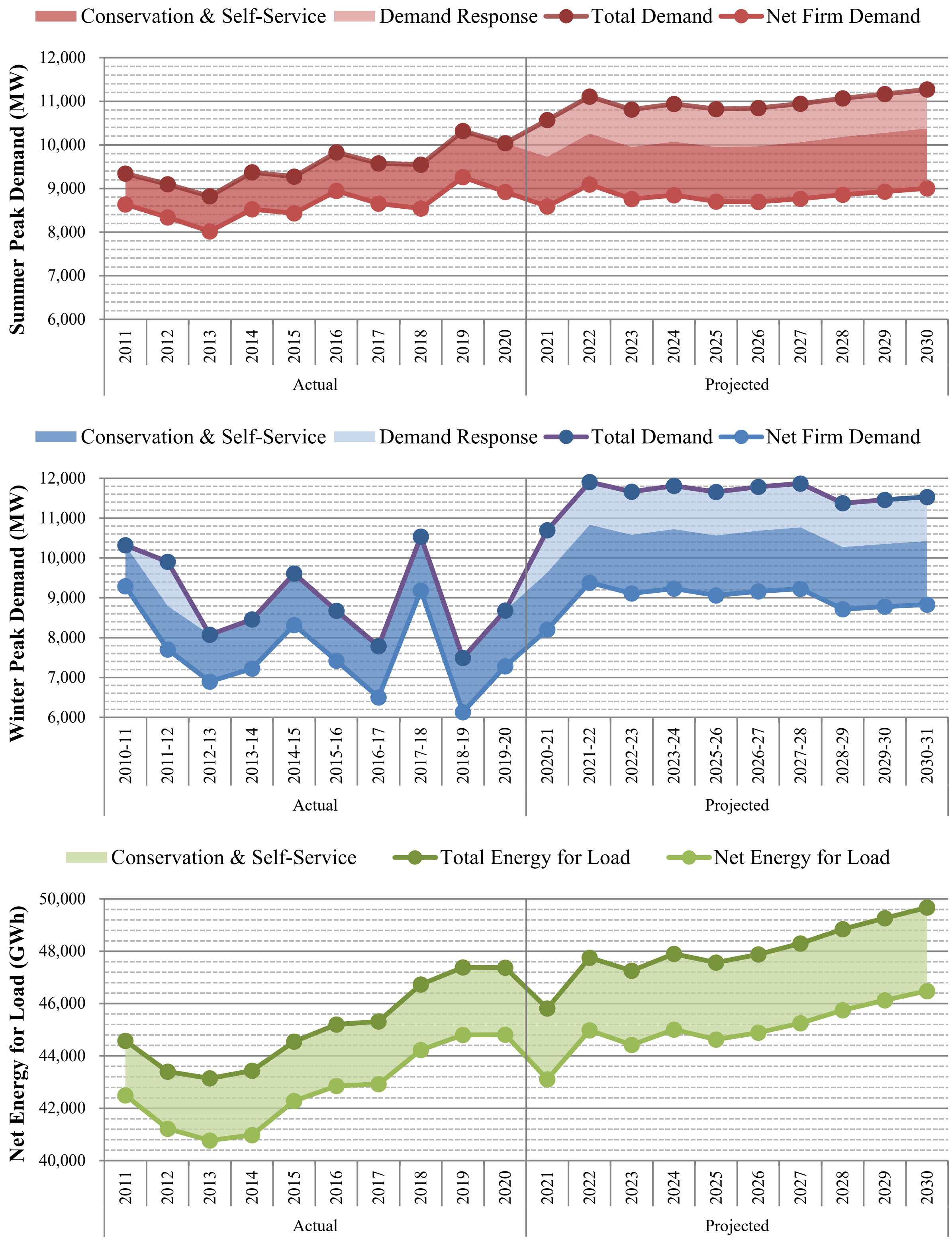
Figure 23: DEF Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 24 show DEF's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. These graphs include the full impact of demand-side management and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand side management goals for the FEECA utilities for the years 2020 through 2024. DEF assumes the trends in these goals will be extended through the forecast period. The utility's 2021 Ten-Year Site Plan reflects these goals.

Figure 24: DEF Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 81 percent of net energy for load. DEF plans to reduce coal usage over the planning period, and to increase renewable energy generation, making natural gas and renewable energy DEF's primary sources of generation in 2030. DEF projects the fourth highest percentage of renewable energy generation in 2030 of the TYSP Utilities.

Table 14: DEF Energy Generation by Fuel Type

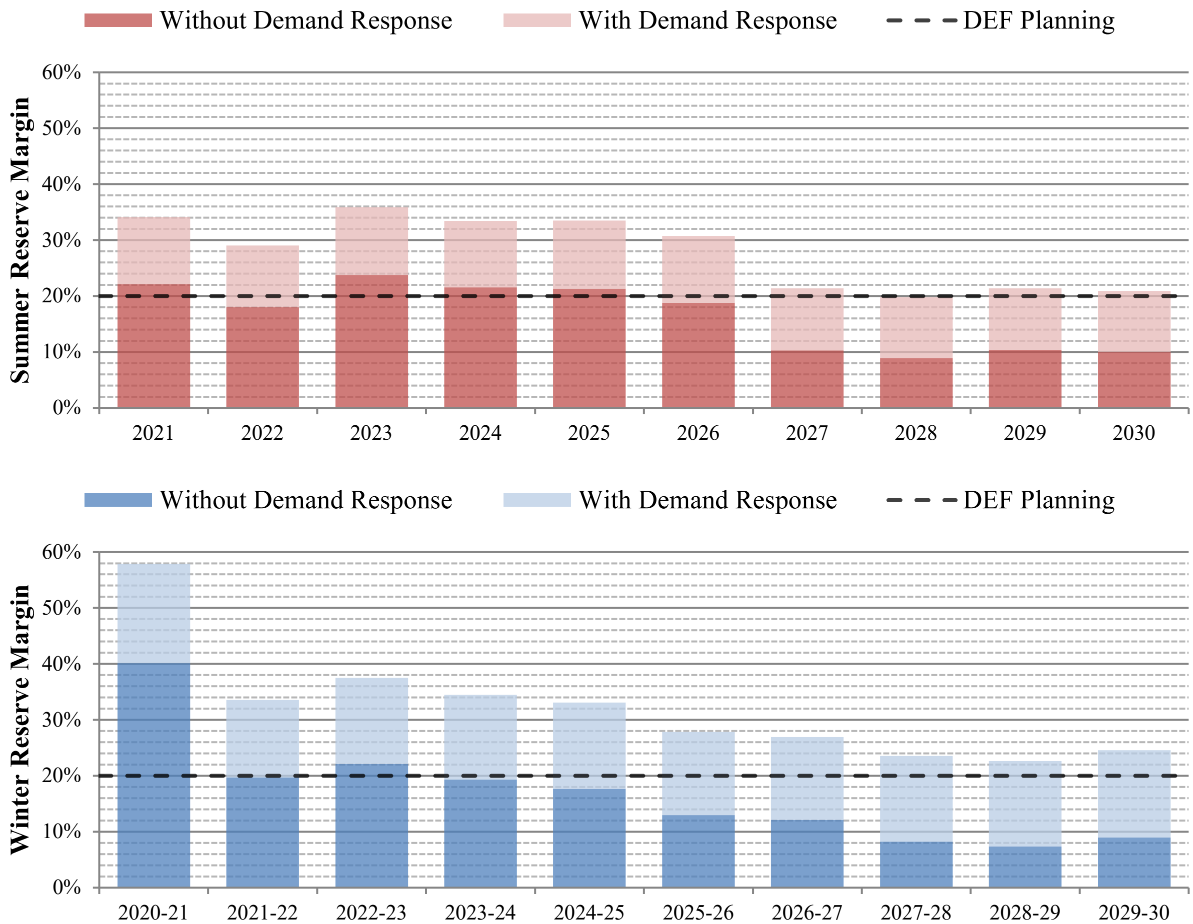
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	36,327	**81.1%**	34,928	**75.1%**
Coal	3,287	**7.3%**	4,190	**9.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	33	**0.1%**	52	**0.1%**
Renewable	1,360	**3.0%**	7,293	**15.7%**
Interchange	1,025	**2.3%**	19	**0.0%**
NUG & Other	2,782	**6.2%**	2	**0.0%**
Total	**44,815**		**46,484**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 25 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are mostly controlled by its summer peaking throughout the planning period. DEF's reserve margin, inclusive of demand response, is projected to be 19.8 percent in the summer of 2028. As DEF approaches this date, the utility will continue to evaluate how to meet its 20 percent reserve margin criterion.

Figure 25: DEF Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 15. DEF plans to retire one gas and several oil-fired units at multiple power plant sites. DEF is adding two combustion turbines, one in 2027 and one in 2029, at undesignated sites. Transmission upgrades to be completed in 2024 will also allow DEF to fully utilize its existing Osprey facility, with the incremental available firm capacity listed in Table 15.

DEF has included 2,025 MW of planned solar additions, which make up approximately 73 percent of DEF's planned total new capacity. In July 2020, DEF petitioned the Commission to implement a Clean Energy Connection program (CEC), which is designed to be a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy centers.[11] The Order approving the CEC program is currently under appeal at the Supreme Court of Florida.

[11] See Docket No. 20200176-EI, *In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.*

Table 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2025	Bayboro P1-4	DFO – CT	171	N/A	
2027	Debary P2-6	DFO – CT	247	N/A	
2027	Bartow P1 & 3	DFO – CT	82	N/A	
2027	University of Florida P1	NG – CT	43	N/A	
Total Retired MW			**543**	N/A	
New Units					
2021	Twin Rivers	PV	75	43	Docket 20200245-EI
2021	Santa Fe	PV	75	43	
2021	Duette	PV	75	42	
2021	Charlie Creek	PV	75	43	
2022	Sandy Creek	PV	75	43	
2022	Fort Green	PV	75	43	
2022	Bay Trail	PV	75	43	
2023	Clean Energy Connection	PV	300	171	Docket No.20200176-EI
2024	Osprey	NG – CC	337	-	Transmission Upgrades
2024	Clean Energy Connection	PV	300	171	Docket No.20200176-EI
2025	Unknown Solar	PV	150	37	
2026	Unknown Solar	PV	150	37	
2027	Unknown CT	NG – CT	214	-	
2027	Unknown Solar	PV	75	19	
2028	Unknown Solar	PV	75	19	
2029	Unknown Solar	PV	75	19	
2029	Unknown CT	NG – CT	214	-	
2030	Unknown Solar	PV	375	47	
Total New MW			**2,790**	**820**	

Net Additions	**2,247**	

Source: 2021 Ten-Year Site Plan

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

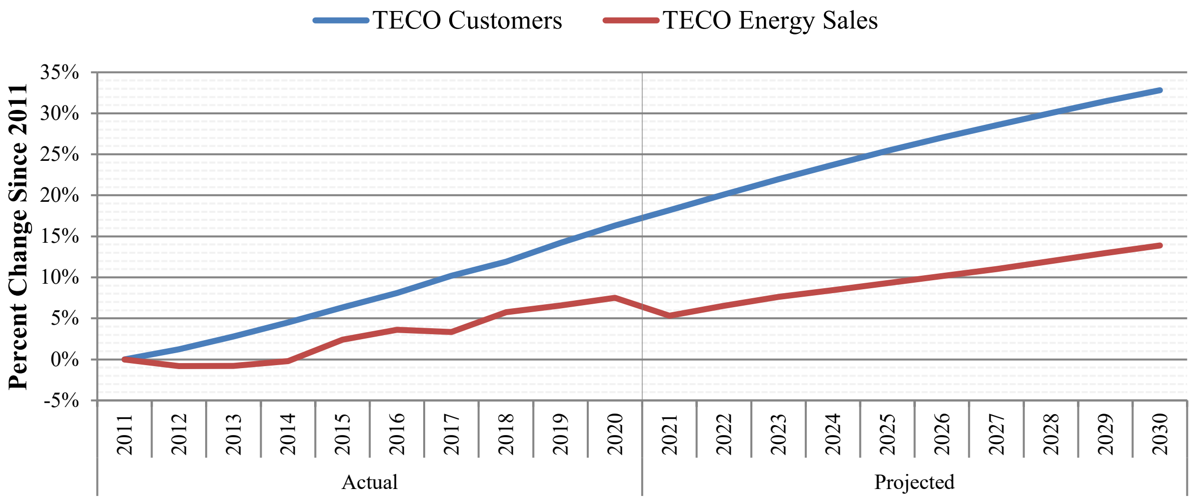
In 2020, TECO had approximately 786,047 customers and annual retail energy sales of 19,954 GWh or approximately 8.6 percent of Florida's annual retail energy sales. Figure 26 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, TECO's customer base has increased by 16.31 percent, while retail sales have increased by 7.49 percent.

TECO's total customer growth in 2020 averaged 1.8 percent with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.31 percent annually. The primary driver of customer growth will be new construction and increasing net in-migration to the utility's service area.

TECO's average annual energy consumption per residential customer increased in 2020 due to hotter than normal weather and more people working/schooling from home due to COVID-19. The utility's commercial, governmental, and industrial average annual consumption per customer decreased in 2020. The COVID-19 impacts on residential and commercial average energy consumption are projected to slowly move back to more normal levels during 2021. Residential average consumption per customer is projected to decline at an average annual rate of 0.2 percent over the next 10 years. The primary drivers behind the declining residential per customer consumption are increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and housing mix. As mining continues to move south and out of TECO's service territory, energy consumption declines in the phosphate sector would emphasize the downward trend of the industrial average energy consumption.

The utility's forecast results indicated that the retail energy sales are projected to grow at an annual average rate of 0.87 percent for the next 10 years.

Figure 26: TECO Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 27 show TECO's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In 2020, TECO continued operating within the 2015-2024 DSM Plan which supports the approved FPSC goals as required by FEECA. The utility's 2021 Ten-Year Site Plan reflects these goals.

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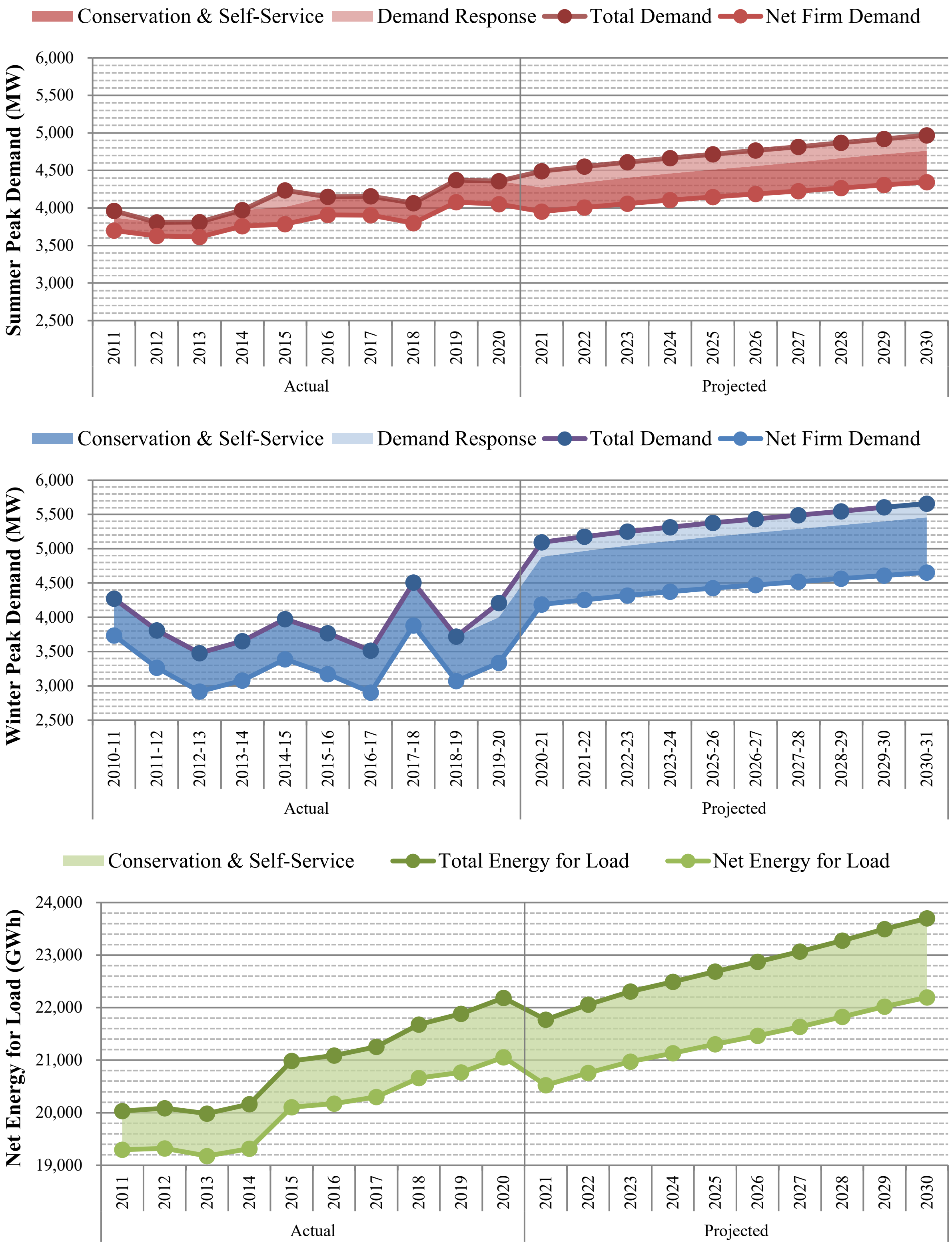
Figure 27: TECO Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. Based on its 2021 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 78 percent of net energy for load. In the future, TECO projects that energy from coal will decrease and energy from renewables will increase. TECO projects that renewable energy will increase from 5.6 percent to 17.8 percent by 2030. TECO projects the third highest percentage of renewable energy generation in 2030 of the TYSP Utilities.

Table 16: TECO Energy Generation by Fuel Type

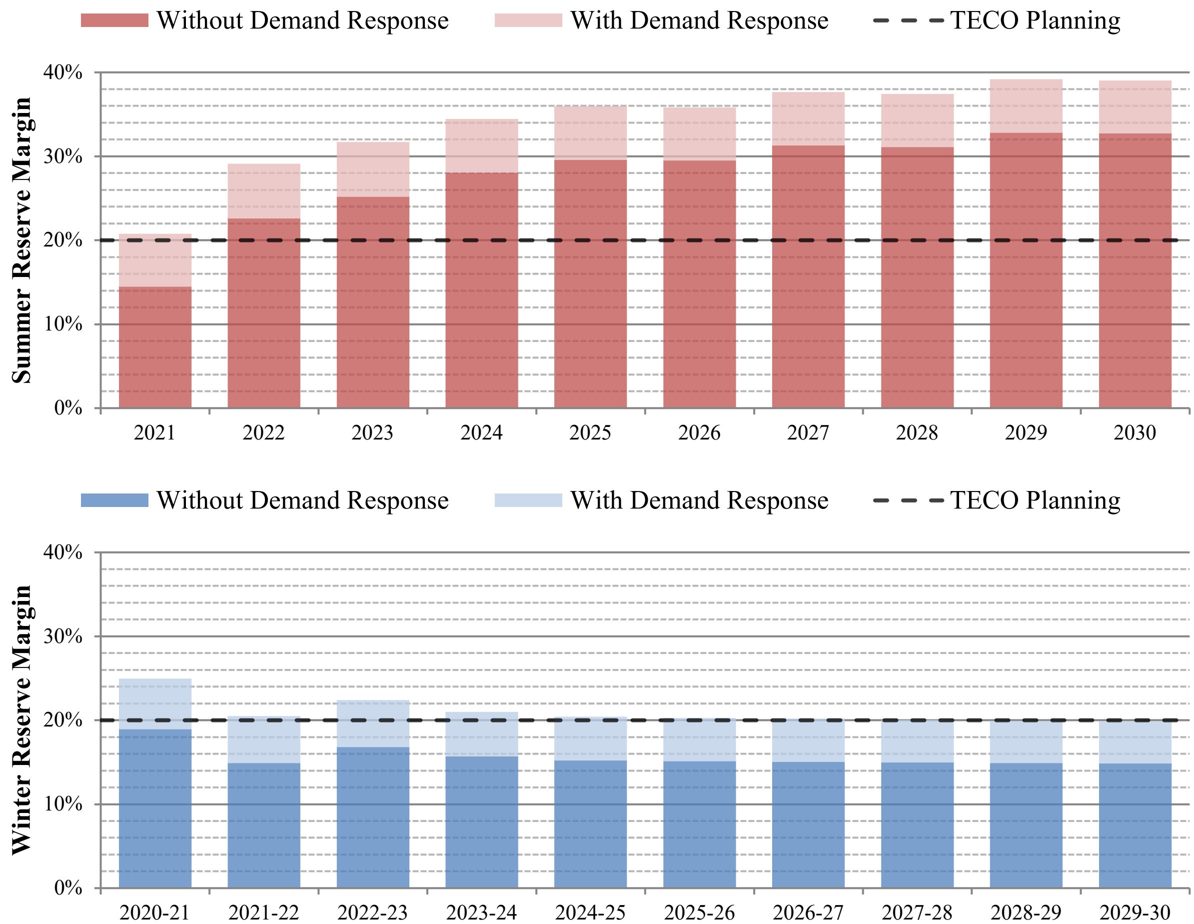
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	16,514	**78.4%**	17,660	**79.5%**
Coal	909	**4.3%**	393	**1.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	1,120	**5.3%**	3,951	**17.8%**
Interchange	1,175	**5.6%**	0	**0.0%**
NUG & Other	1,335	**6.3%**	201	**0.9%**
Total	**21,055**		**22,205**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 28 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs begin to be controlled by its winter peak this year. TECO's current and planned investments in solar generation contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

Figure 28: TECO Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

TECO plans two unit retirements and multiple unit additions during the planning period, as described in Table 17. TECO anticipates retiring its natural gas-fired Big Bend Units 2 and 3 and converting its stand-alone Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit. The Florida Department of Environmental Protection has found that a determination of need is not necessary for this conversion.

TECO also anticipates adding several solar projects over the planning period. The utility has included 1,262 MW of planned solar. All planned solar additions make up approximately 48 percent of TECO's planned total new capacity.

TECO also plans the addition of several distributed energy resources throughout its territory. Over the planning period, the utility also plans to add 300 MW of battery storage. These additions are projected to yield improved environmental and reliability benefits, to enhance operational flexibility, and to improve system resiliency.

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2021	Big Bend 2	NG – ST	385	N/A	
2023	Big Bend 3	NG – ST	395	N/A	
Total Retirements			**780**	N/A	
New Units					
2021	Durrance Solar	PV	60	35	
2021	Mountain View Solar	PV	53	30	
2021	Big Bend II Solar	PV	25	14	
2021	Jamison Solar	PV	75	42	
2021	Magnolia Solar	PV	75	42	
2021	Big Bend CT 5 & 6	NG – CT	720	-	Converted to CC in 2022
2022	Big Bend CC Conversion	NG – CC	335	-	Incremental Capacity of CC
2022	Laurel Oaks Solar	PV	67	37	
2022	Riverside Solar	PV	65	36	
2022	Big Bend III Solar	PV	22	12	
2022	Palm River Dairy Solar	PV	70	39	
2023	Alafia Solar	PV	50	28	
2023	Wheeler Solar	PV	75	42	
2023	Dover Solar	PV	25	14	
2024	Reciprocating Engine	NG – IC	37	-	2 Reciprocating Engines
2024	Future Solar 1	PV	150	84	
2025	Battery Storage 1	BAT	50	-	
2026	Battery Storage 2	BAT	50	-	
2026	Future Solar 2	PV	150	84	
2027	Battery Storage 3	BAT	50	-	
2028	Battery Storage 4	BAT	50	-	
2028	Future Solar 3	PV	150	84	
2029	Battery Storage 5	BAT	50	-	
2030	Battery Storage 6	BAT	50	-	
2030	Future Solar 4	PV	150	84	
Total New Units			**2,654**	**707**	
Net Additions			**1,874**		

Source: 2021 Ten-Year Site Plan

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants in the All-Requirements Power Supply Project (ARP) are addressed in the utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. For a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2021 Ten-Year Site Plan suitable for planning purposes.

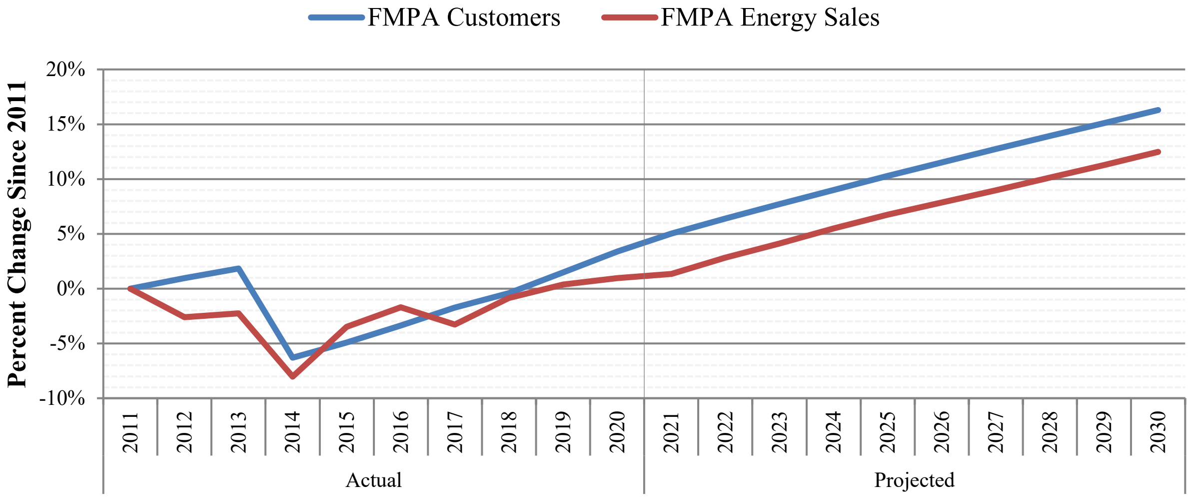
Load & Energy Forecasts

In 2020, FMPA had approximately 271,118 customers and annual retail energy sales of 5,876 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 29 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, FMPA's customer base has increased by 3.39 percent, while retail sales have increased by 0.95 percent. FMPA's retail energy sales growth rate is anticipated to exceed its historic 2020 peak in 2021.

FMPA noted that its customer energy usage has been flat due to a decline in both the residential and non-residential sectors in recent years. There are countervailing factors that influence usage. In general, declines in electricity prices, improvements in the employment situation, increased average income, and reductions in vacancy rates and under-occupied accounts have a small upward impact on usage. Concurrently, the lingering effects of the recent 2007-08 recession in terms of reduced propensity to spend, a continued orientation to conservation, and continued improvement in energy efficiency, driven primarily from technological advances, equipment standards, and building codes, place downward pressure on average usage. These impacts have been offset by strong customer count gains in certain areas of the utility's service territories, which has resulted in continued recovery in net energy for load since the 2007-08 recession.

For the current 10-year forecast horizon, the utility is projecting a 1.14 percent average annual growth rate for customer base, and 1.17 percent average annual growth rate for retail energy sales.

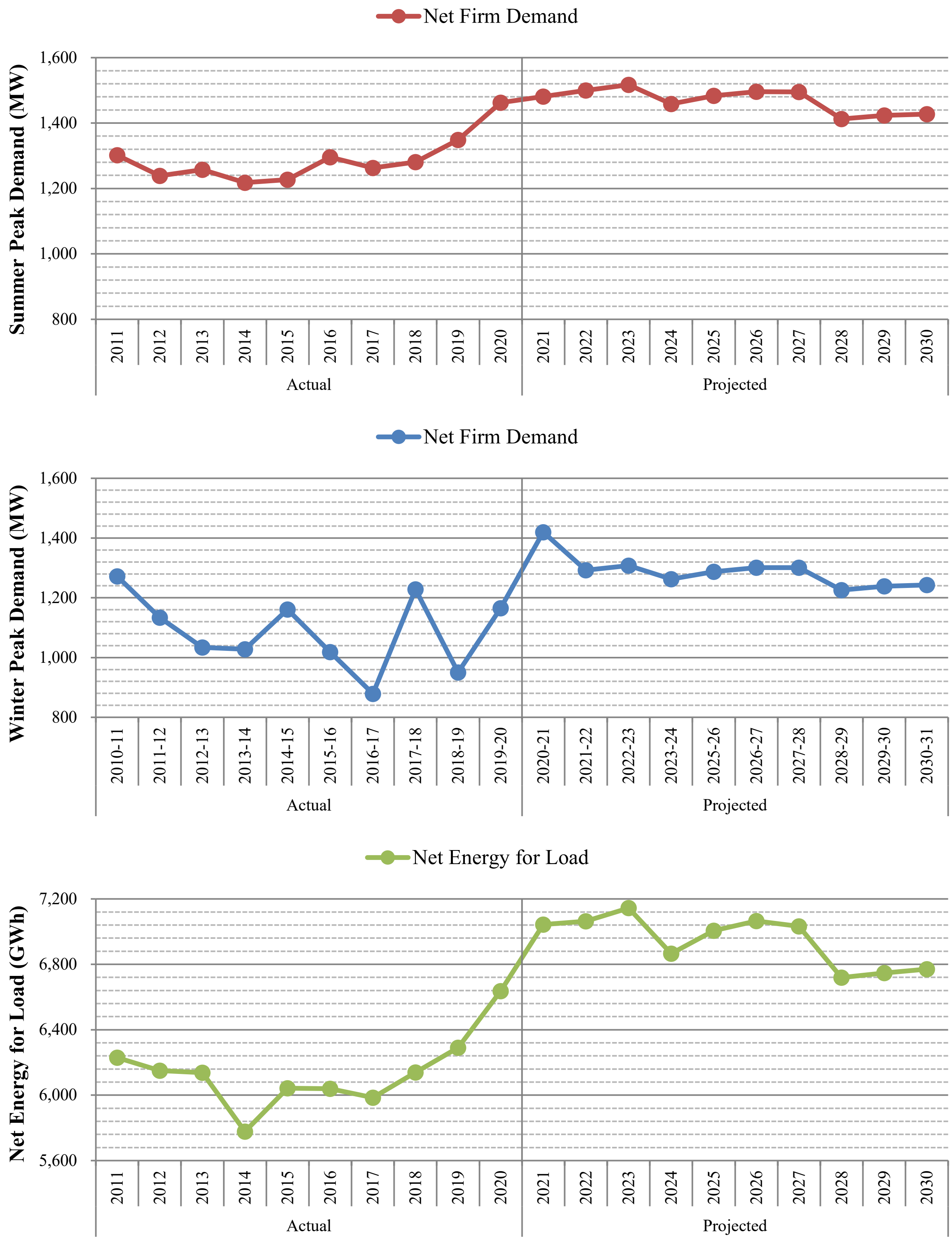
Figure 29: FMPA Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 30 show FMPA's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

Figure 30: FMPA Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 18 shows FMPA's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects to end energy generation from coal by 2026, but approximately 93 percent of energy would still be sourced from natural gas and nuclear. FMPA projects serving 7 percent of its net energy for load with renewable resources by the end of the planning period.

Table 18: FMPA Energy Generation by Fuel Type

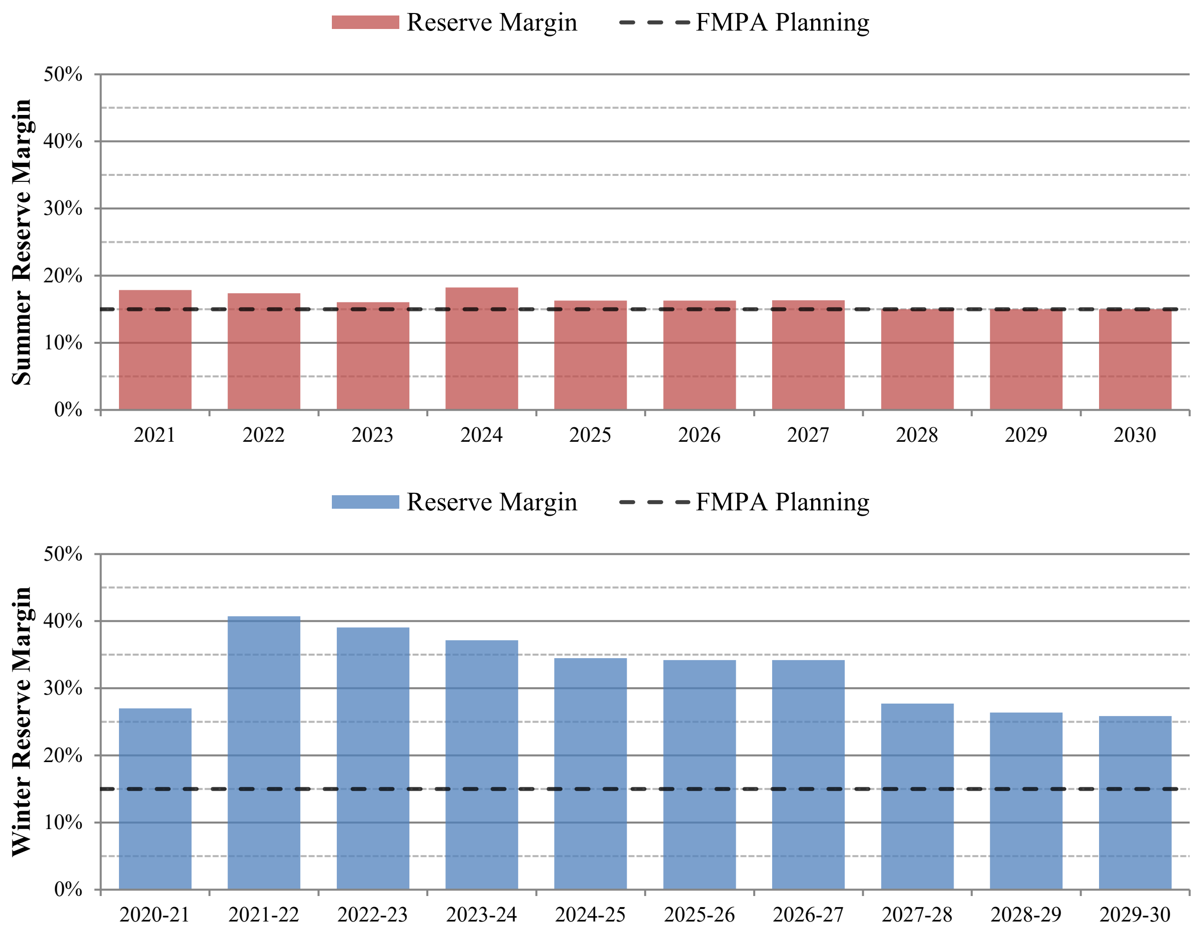
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	5,189	**78.2%**	5,921	**87.4%**
Coal	924	**13.9%**	0	**0.0%**
Nuclear	413	**6.2%**	376	**5.6%**
Oil	3	**0.1%**	1	**0.0%**
Renewable	108	**1.6%**	473	**7.0%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**6,637**		**6,771**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 31 displays the forecast planning reserve margin for FMPA through the planning period for both seasons, inclusive of impacts from energy efficiency programs. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 31: FMPA Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

FMPA plans no unit additions or retirements during the planning period.

Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2021 Ten-Year Site Plan suitable for planning purposes.

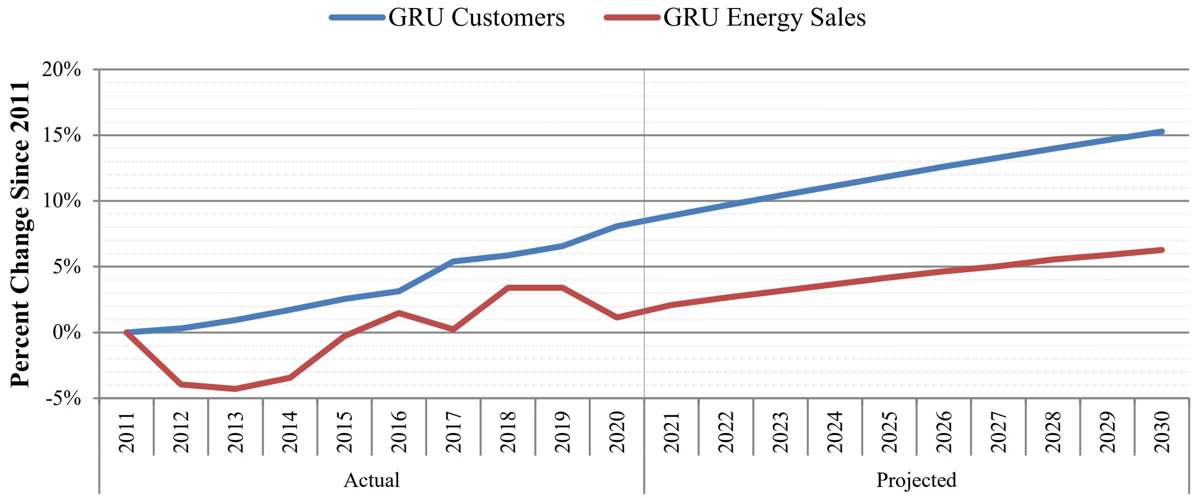
Load & Energy Forecasts

In 2020, GRU had approximately 99,714 customers and annual retail energy sales of 1,790 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Over the last 10 years, GRU's customer base has increased by 8.07 percent, while retail sales have increased by 1.13 percent. Figure 32 illustrates GRU's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. It shows that GRU's retail energy sales are anticipated to exceed its historic 2019 peak in 2024 during this planning period.

GRU experienced a decline in per customer energy consumption at an annual rate of 0.24 percent and 1.24 percent, respectively, for its residential and non-residential classes over the past 10 years. For the next 10 years, the utility projects the declining rates of energy consumption of 0.25 percent and 0.30 percent per year, respectively, for these classes. Some of the factors believed to effect consumption per customer historically include the 2007-08 recession, increasing electricity prices, and improved building envelopes and energy efficiency standards (regulatory) and measures (utility induced). GRU noted that, in general, the COVID-19 Pandemic resulted in increased residential usage and reduced non-residential usage.

For the current 10-year forecast horizon, the utility's customer numbers are projected to grow at an annual average rate of 0.64 percent, and the retail energy sales are projected to grow at an annual average rate of 0.45 percent. The utility indicated that growth of retail energy sales is positively influenced by customer growth and offset negatively by consumption per customer.

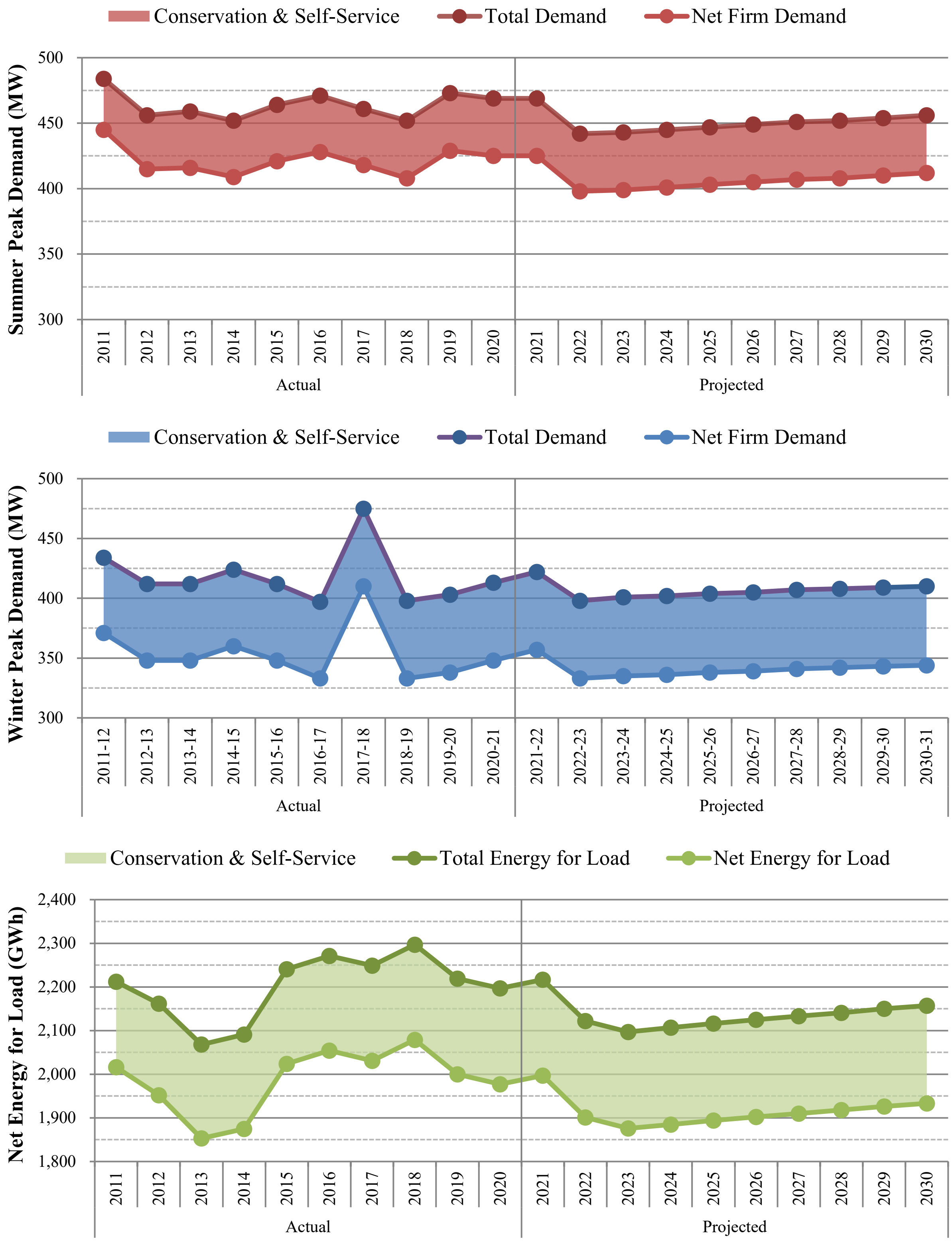
Figure 32: GRU Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 33 show GRU's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 33 include the impact of these demand-side management programs.

Figure 33: GRU Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows GRU's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. In 2020, natural gas was the primary fuel followed by renewables and coal respectively. By 2030 natural gas and renewables are expected to increase in usage, while coal usage is expected to end by 2022.

Table 19: GRU Energy Generation by Fuel Type

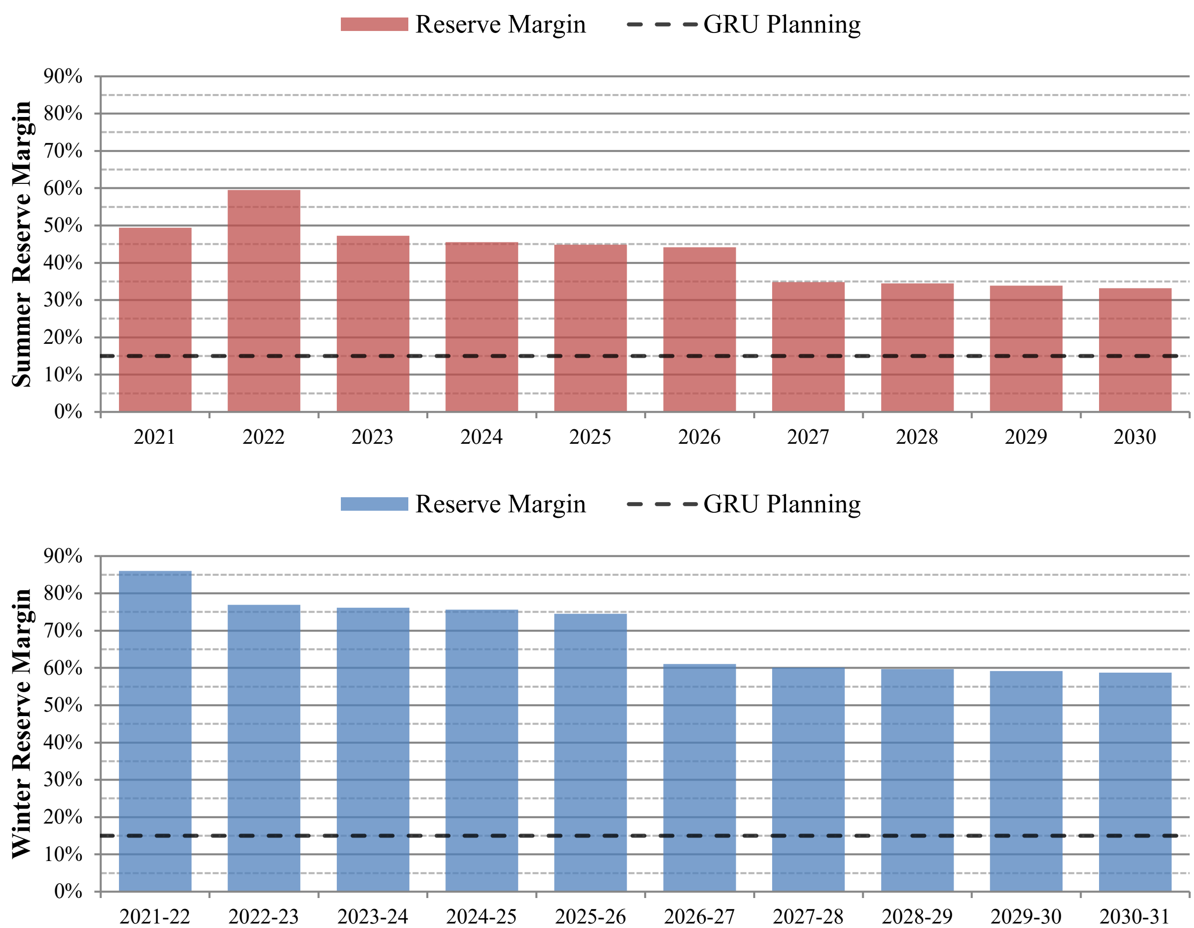
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	1,278	**64.6%**	1,410	**72.9%**
Coal	215	**10.9%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	394	**19.9%**	501	**25.9%**
Interchange	90	**4.6%**	22	**1.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**1,977**		**1,933**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 34 displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin.

Figure 34: GRU Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

GRU currently plans to retire a natural gas-fired steam unit in 2022, and two natural gas-fired combustion turbines in 2026, as described in Table 20. As a smaller utility, single units can have a large impact upon reserve margin.

Table 20: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2022	Deerhaven FS01	NG – ST	75
2026	Deerhaven GT01 & GT02	NG – CT	35
Total Retirements			**110**
Net Additions			**(110)**

Source: 2021 Ten-Year Site Plan

JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

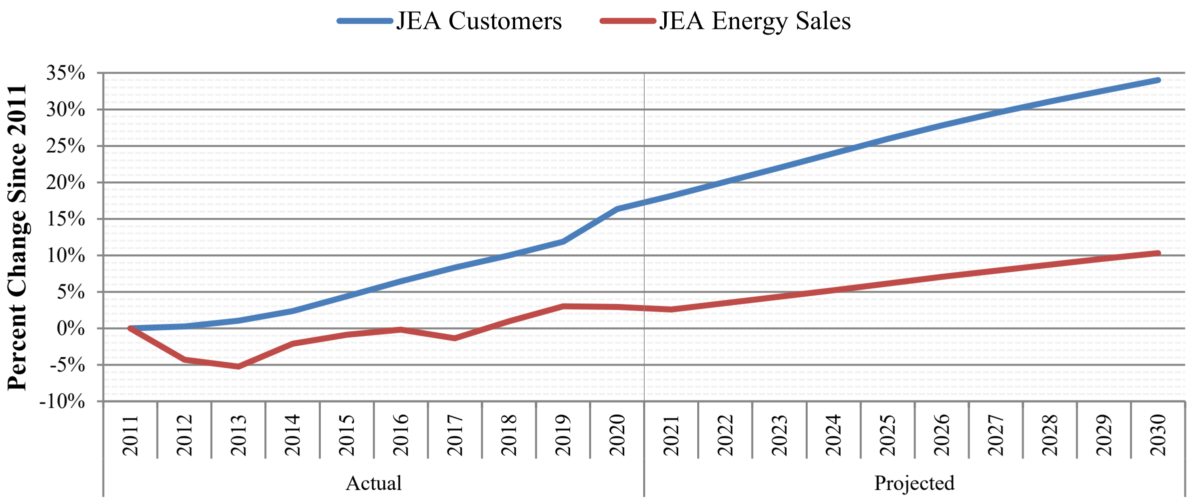
In 2020, JEA had approximately 483,471 customers and annual retail energy sales of 12,319 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Figure 35 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, JEA's customer base has increased by 16.06 percent, while retail sales have increased by 2.93 percent.

JEA noted that overall, Moody's Analytics forecast for all parameters used in the utility's 2021 Ten-Year Site Plan forecast of customer growth are lower as compared to the previous forecasts. As a result, the Commercial and Industrial customer forecasts are lower as compared to previous years. The residential customer forecast however, shows a slightly higher forecasted customer growth rate as compared to previous year's forecasts.

The utility's growth rate for average annual energy consumption per customer is projected to decrease by 0.2 percent and 0.8 percent, respectively, for residential and commercial class in the forecast period of 2021 through 2030. JEA noted that demand-side management programs are one of the contributors to the decrease in annual energy consumption per residential customer. Several other factors that contribute to the declining trend include customer behavioral changes, increase in electric rates, housing type and federal central air conditioner-related requirements. However, JEA projected a 0.6 percent growth in the industrial average annual energy consumption for the next 10 years due to certain customers' business expansion and the utility's effort of service improvement.

For the next 10 years, the JEA's forecast results indicate that the customer numbers are projected to grow at an annual average rate of 1.41 percent; and the retail energy sales are projected to grow at an annual average rate of 0.81 percent.

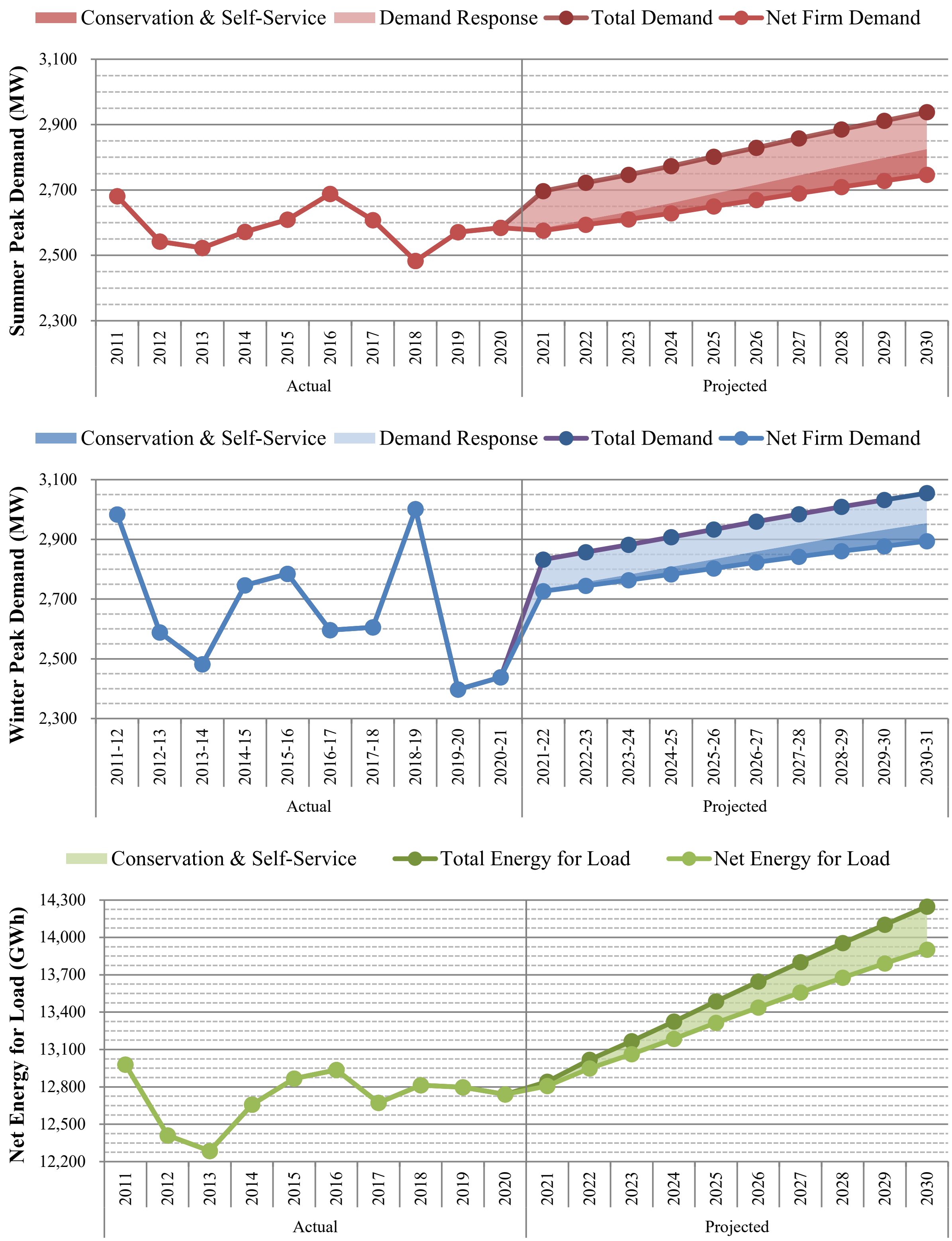
Figure 35: JEA Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 36 show JEA's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak.

Figure 36: JEA Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the FPSC established demand side management goals for the FEECA utilities for the years 2020 through 2024. The utility's 2021 Ten-Year Site Plan reflects these goals.

Fuel Diversity

Table 21 shows JEA's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. While natural gas was the dominant fuel source in 2020, coal was JEA's second most utilized fuel source. JEA's 2021 Ten-Year Site plan projects that a majority of JEA's net energy for load will continue to come from natural gas and coal in 2030.

Table 21: JEA Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	8,229	**64.6%**	7,227	**52.0%**
Coal	3,020	**23.7%**	2,986	**21.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	3	**0.0%**	4	**0.0%**
Renewable	144	**1.1%**	660	**4.7%**
Interchange	1,344	**10.5%**	3,027	**21.8%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,739**		**13,903**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 37 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned purchased power agreements with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak.

Figure 37: JEA Reserve Margin Forecast

Source: 2021 Ten-Year Site Plan

Generation Resources

JEA plans no unit additions during the planning period. JEA plans to retire Northside Unit 3 sometime during the planning period. However, a date has yet to be selected. Due to this, Northside Unit 3 is still included in the reserve margin calculations for the 2021 Ten-Year Site Plan.

Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

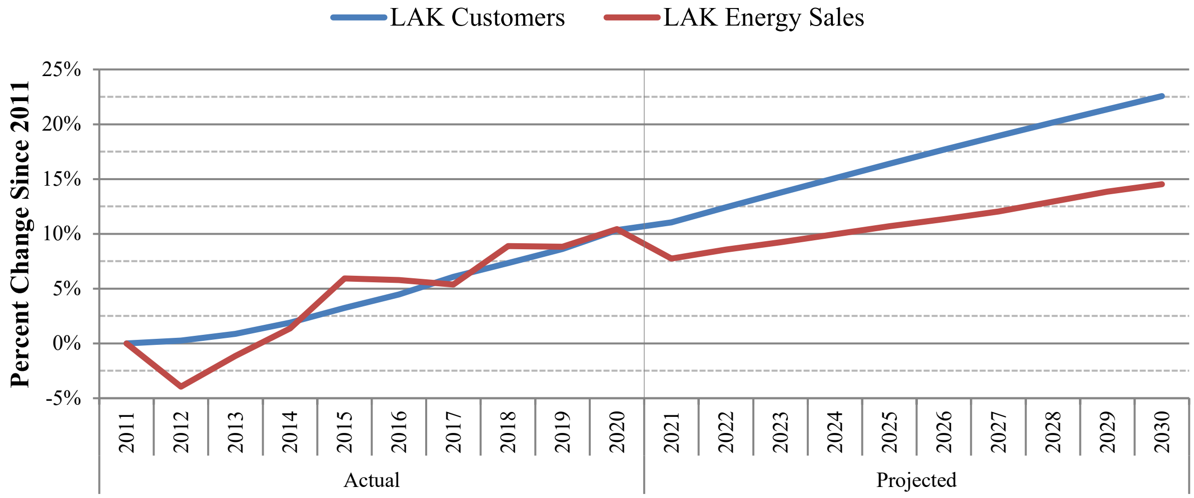
In 2020, LAK had approximately 134,321 customers and annual retail energy sales of 3,163 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Figure 38 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, LAK's customer base has increased by 10.35 percent, while retail sales have grown by 10.44 percent.

In recent years, the LAK's service area in Polk County has seen a boom in e-commerce warehouse development due to its central location in Florida. Notably, Amazon moved its air hub from Tampa to Lakeland in the summer of 2020. In addition, the local business community is very active in promoting central Florida encouraging a diversity of industries to relocate there. LAK experienced 1.6 percent total customer growth in 2020 which is the highest growth rate for the utility in the past 10 years.

The utility noted that its residential average energy consumption has been declining and this trend is expected to continue. The main factors that contribute to the decline include increased appliance energy efficiency, improved building shell insulation, and changes in residential building type mix. LAK's commercial average energy consumption has also been declining, and this trend is expected to continue. Main contributors to the historical decline are lighting upgrades, appliance energy efficiency improvements, and the customer adoption of energy management systems. LAK is forecasting a flattening of the industrial average energy consumption mainly because a small number of customers are projected to be added, and such customers are expected to be mostly classified in the "small demand" industrial category.

LAK noted that although the average energy consumption is declining or flat for all three main rate classes, positive customer growth rates are expected to compensate for average use declines. For the next 10 years, the utility's forecast results indicated that its number of customers are projected to grow at an annual average rate of 1.10 percent, and its retail energy sales are projected to grow at an annual average rate of 0.68 percent.

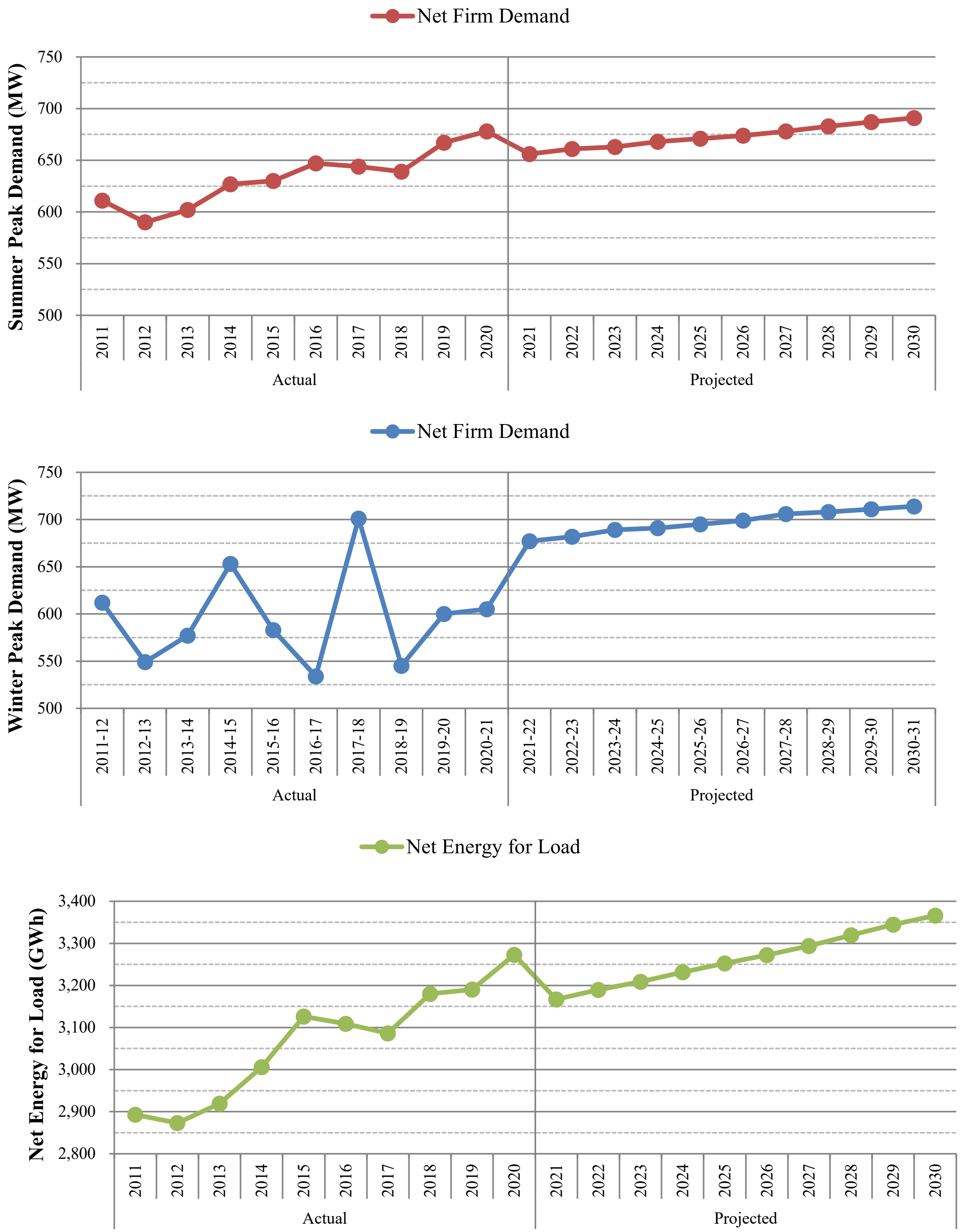
Figure 38: LAK Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 39 show LAK's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 39: LAK Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 22 shows LAK's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. LAK uses natural gas as its primary fuel type for energy, with coal representing about 14 percent net energy for load. While natural gas generation is anticipated to increase over the next 10 years; generation by coal is projected to be phased out by March 2021.

Table 22: LAK Energy Generation by Fuel Type

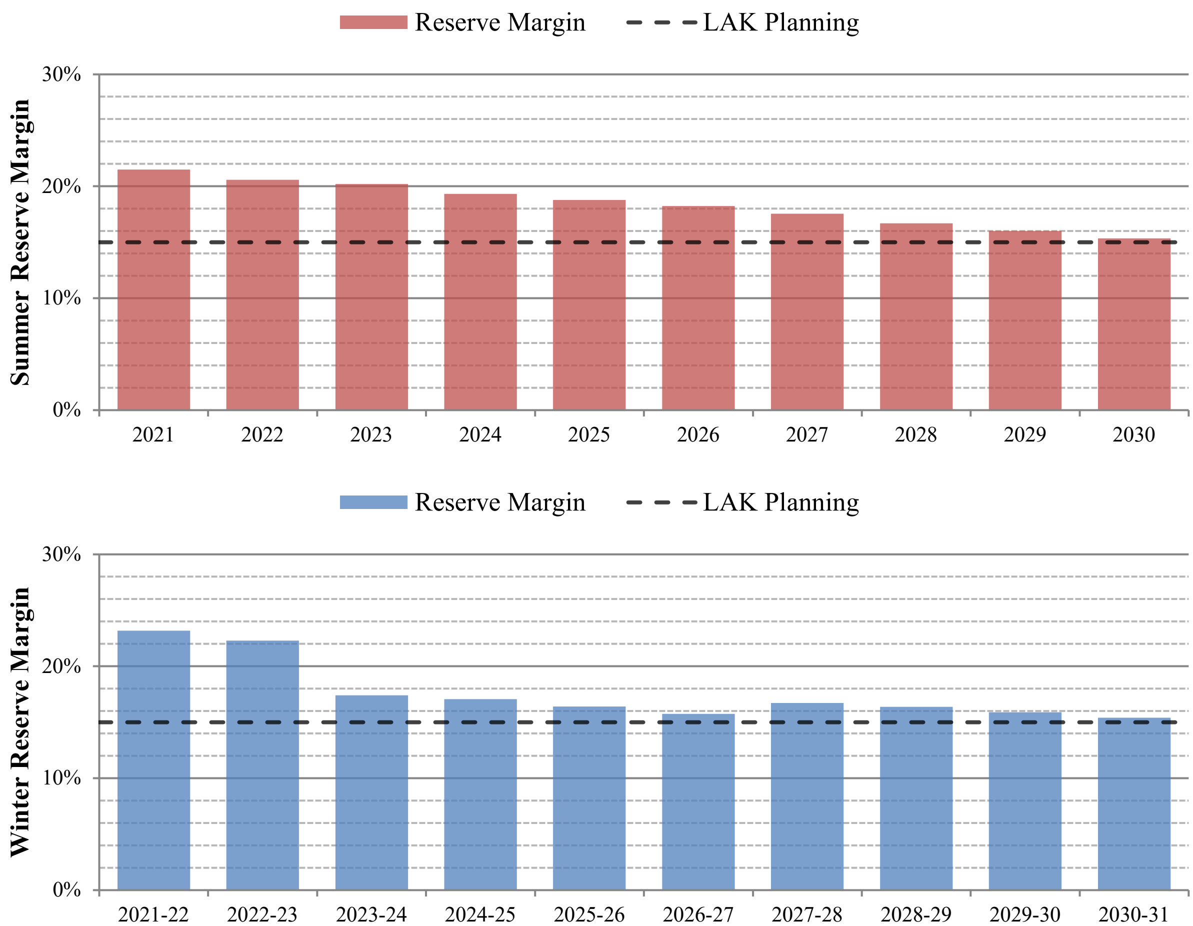
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	2,118	**64.7%**	2,956	**87.8%**
Coal	452	**13.8%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	1	**0.0%**
Renewable	28	**0.9%**	161	**4.8%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	675	**20.6%**	248	**7.4%**
Total	**3,274**		**3,366**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 40 displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represented 50 percent of summer net firm peak demand in 2019.

Figure 40: LAK Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

LAK plans on retiring its only coal-fired generating unit, and adding a set of natural gas internal combustion engines during the planning period, as detailed in Table 23.

Table 23: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2021	McIntosh Unit No. 3	BIT-ST	205	
New Units				
2024	Unnamed IC	NG-IC	100	5 Reciprocating Engines
Net Additions			**(105)**	

Source: 2021 Ten-Year Site Plan and Data Responses

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's seventh largest electric utility and second largest municipal utility. The utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2021 Ten-Year Site Plan suitable for planning purposes.

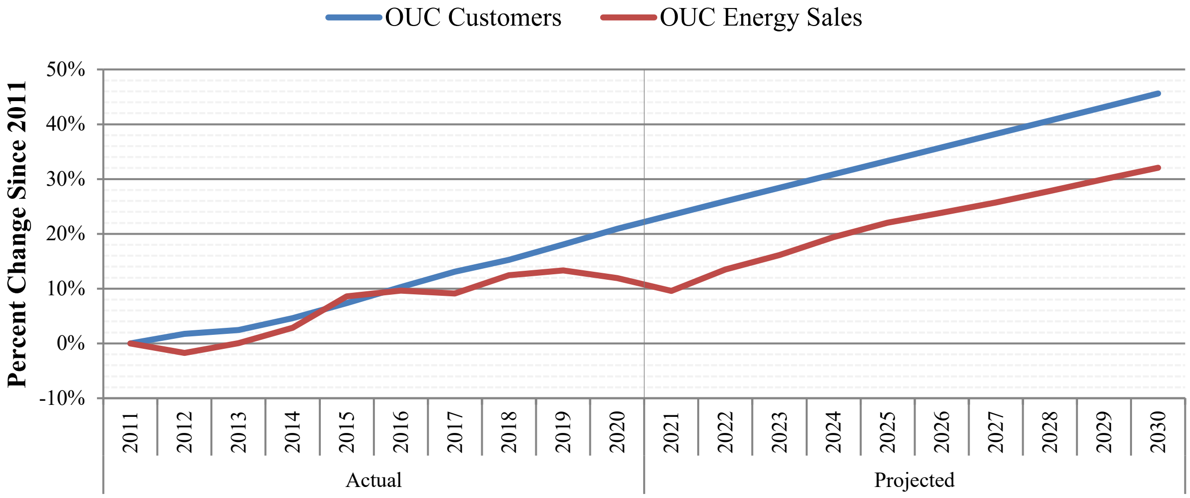
Load & Energy Forecasts

In 2020, OUC had approximately 253,448 customers and annual retail energy sales of 6,740 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer numbers have had an average annual growth of 2.13 percent, and retail sales had an average annual growth of 1.26 percent. Figure 41 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011.

Over the last 10 years, OUC's customer base has increased by 20.90 percent, while retail energy sales have increased by 11.94 percent, approximately. The utility expects a continued growth in customer numbers at an average annual rate of 1.85 percent, and retail sales at an average annual rate of 2.10 percent for the current forecast horizon. OUC noted that the main contributors to the higher customer growth include the increased population and household numbers in its service area. The main drivers for a higher expected growth rate of the energy sales than in the past include the recovery from COVID-19 effects, the projected growth in electric vehicle charging load and major commercial expansions from Universal Studios and the Orlando International Airport that are largely outside of normal growth.

OUC also noted a recent decline in average residential customer energy usage is attributed to the increased saturation of more efficient HVAC equipment and other electrical devices as well as customer conservation efforts. The utility's forecasted residential average energy usage is expected to remain relatively flat as increased electric vehicle charging mitigates further saturation of more efficient electrical equipment and conservation efforts. Commercial sales have also shown a slight, long-term declining use per customer trend that has been greatly exacerbated by the impacts of COVID-19 in 2020, which, however, is expected to nearly recover to pre-COVID levels by the end of the forecast period.

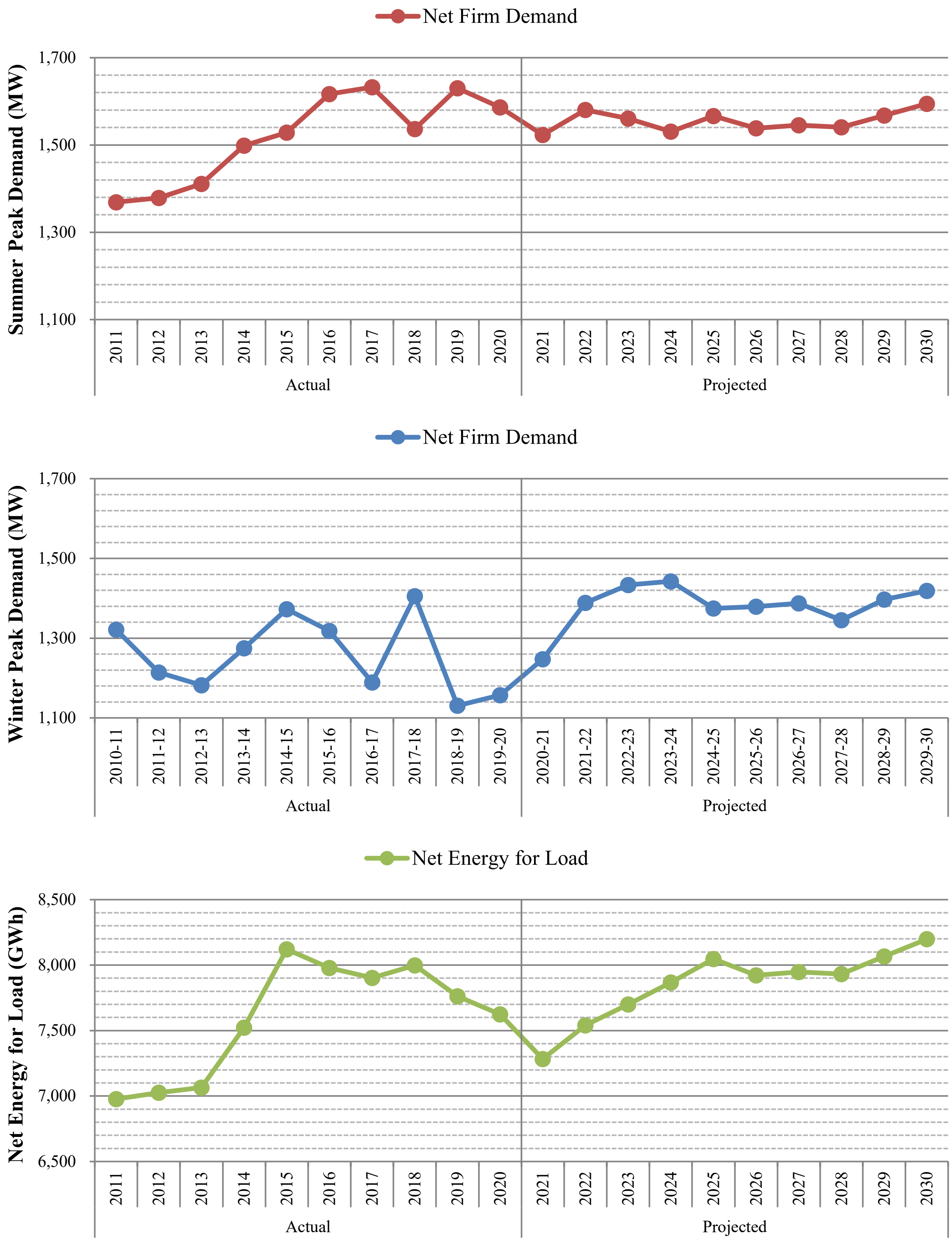
Figure 41: OUC Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 42 show OUC's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. These graphs include the impact of the utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption. In November 2019, the FPSC established demand side management goals for the FEECA utilities for the years 2020 through 2024. The utility's 2021 Ten-Year Site Plan reflects these goals.

Figure 42: OUC Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 24 shows OUC's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. In 2020, approximately 53 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met 36 percent of the demand. By 2030, OUC projects an increase in renewable energy generation from 3 percent to 13 percent. While coal generation is expected to come to an end by 2027.

Table 24: OUC Energy Generation by Fuel Type

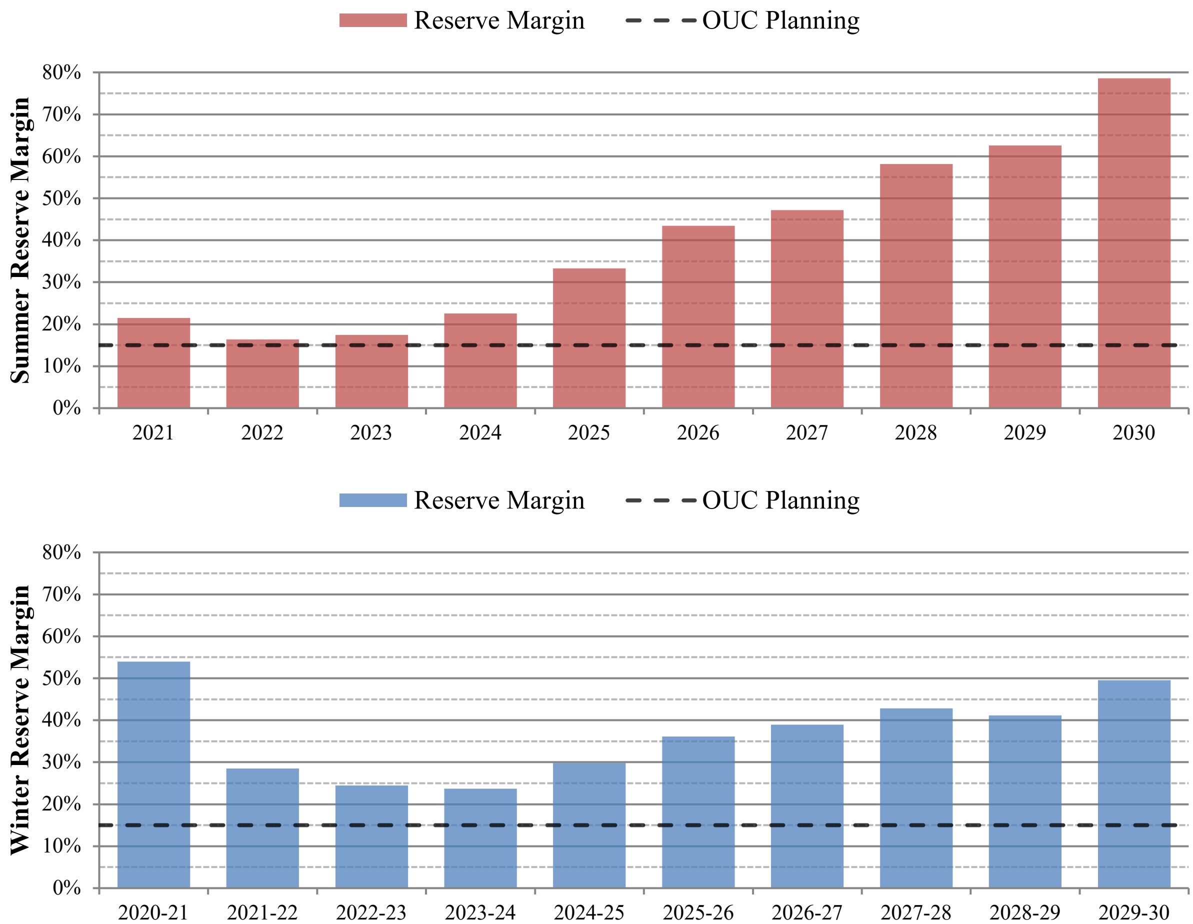
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	4,090	**53.6%**	6,584	**80.3%**
Coal	2,778	**36.4%**	0	**0.0%**
Nuclear	500	**6.6%**	587	**7.2%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	258	**3.4%**	1,027	**12.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,626**		**8,198**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 43 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand until 2024.

Figure 43: OUC Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

OUC plans no unit additions or retirements during the planning period, but is increasing its amount of purchased power through purchased power agreements with solar and battery energy storage developers. This is reflected in the increase in reserve margin, especially summer net firm demand where solar facilities provide more reliability benefits.

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

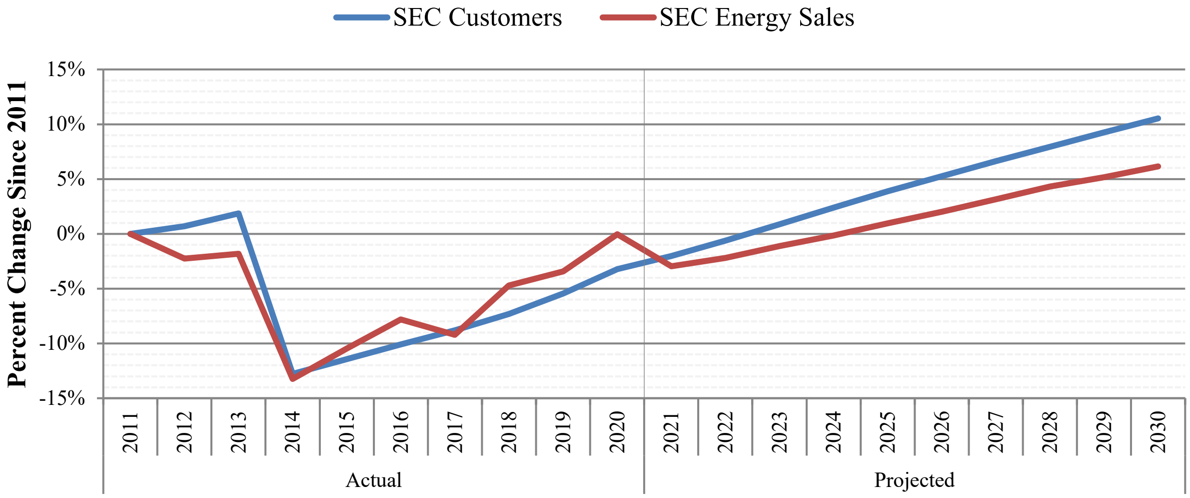
In 2020, SEC member cooperatives had approximately 821,738 customers and annual retail energy sales of 14,934 GWh or approximately 6.4 percent of Florida's annual retail energy sales. Figure 44 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. It shows that SEC's retail energy sales are anticipated to exceed its historic 2011 peak in 2025 during this planning period.

SEC's current Ten-Year Site Plan indicated that over the last 10 years, the utility members' aggregate customer base has decreased by 3.22 percent, compared to a 5.07 percent decrease shown in SEC's forecast last year for the 2010-2019 period. The negative 10-year customer growth rate is attributed to a substantial growth decline in 2014 when one member cooperative, Lee County Electric Cooperative, elected to end its membership with SEC. Over the last 10 years, the utility's retail sales have decreased by 0.03 percent, compared to 10.14 percent decrease indicated in the forecast last year for 2010-2019.

In 2019 and 2020, SEC's total customers grew 2.01 percent and 2.35 percent, respectively. The utility noted that in recent years its number of customers has grown at a faster rate than the State of Florida as a whole and that this trend is expected to continue. SEC indicated that the leading indicators for load growth are Florida's expanding economy and net migration prospects into the state, especially from "baby boomer" retirees. Customer growth and business activity are expected to drive system growth, while downward pressure is expected to come from flattening and declining residential end-use due to growth in efficient technologies, renewable generation, and alternative resources.

For the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 1.35 percent, and an average annual growth rate in its retail energy sales of 1.00 percent.

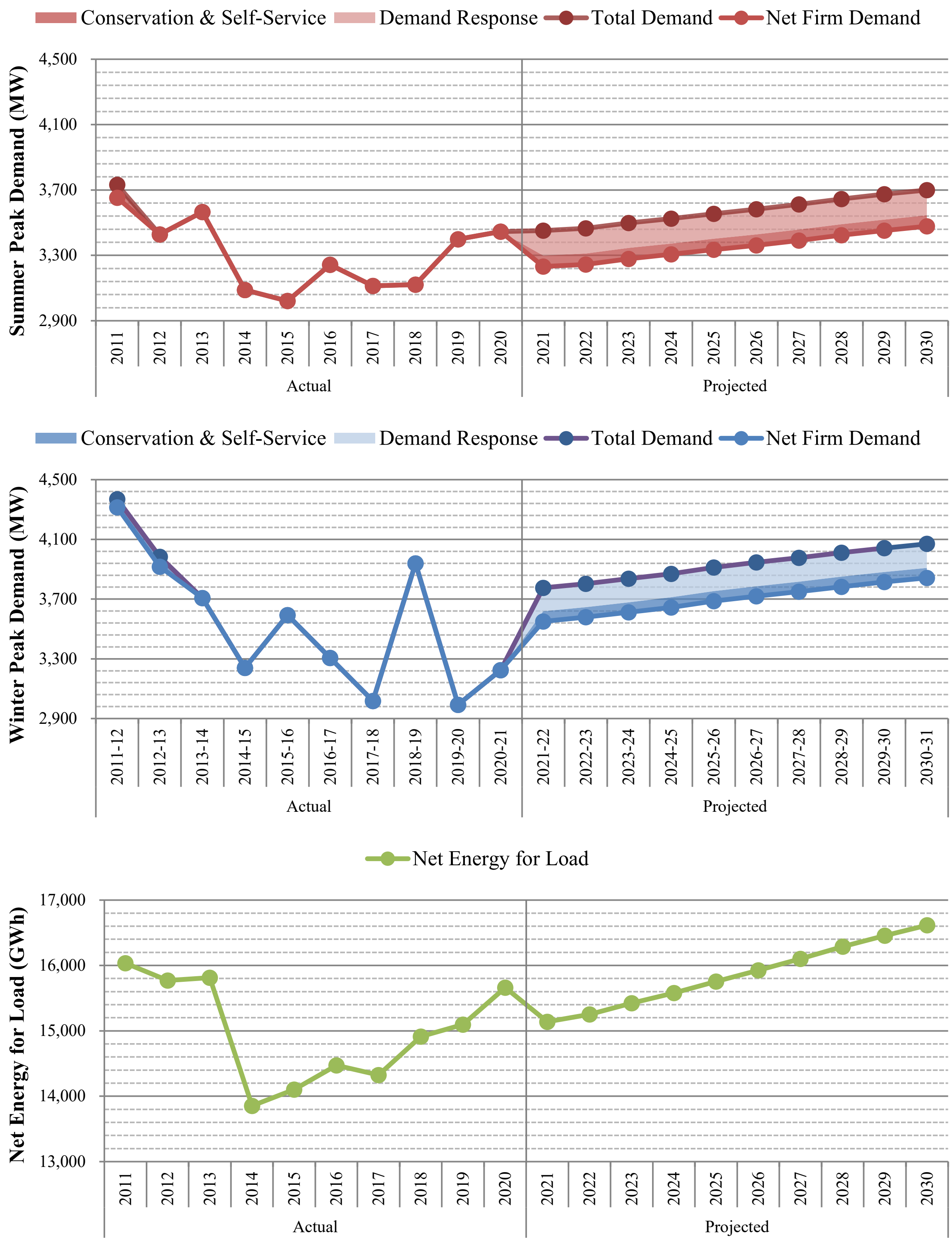
Figure 44: SEC Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 45 show SEC's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 45.

Figure 45: SEC Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 shows SEC's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. In 2020, SEC used coal as its primary source of fuel, while natural gas was the second most used fuel. By 2030 natural gas usage is expected to become the primary fuel source.

Table 25: SEC Energy Generation by Fuel Type

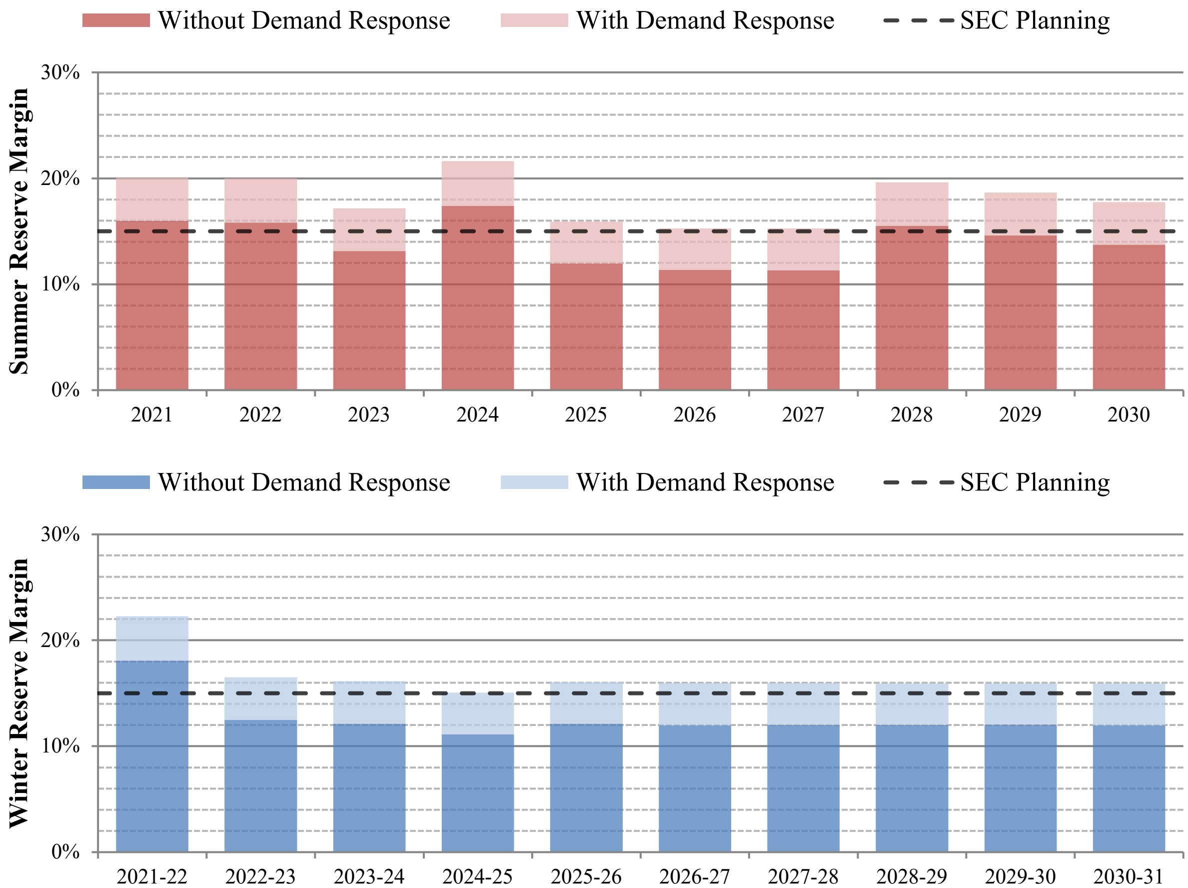
Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	4,421	**28.3%**	13,746	**82.7%**
Coal	6,588	**42.2%**	1,261	**7.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	21	**0.1%**	3	**0.0%**
Renewable	588	**3.8%**	767	**4.6%**
Interchange	4,004	**25.6%**	759	**4.6%**
NUG & Other	0	**0.0%**	79	**0.5%**
Total	**15,622**		**16,615**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 46 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 46: SEC Reserve Margin Forecast



Source: 2021 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add two units during the planning period, as described in Table 26. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[12] Consistent with its need determination filing, SEC plans to retire one of its coal-fired SGS units in 2022, and the Seminole CC Facility is expected to be in-service by 2022. A second unnamed unit is forecast to come online in 2030.

[12] Order No. PSC-2018-0262-FOF-EC, issued May 25, 2018, in Docket No. 20170266-EC, *In re: Petition to determine need for Seminole combined cycle facility, by Seminole Electric Cooperative, Inc.*

Table 26: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2022	SGS Unit 1 or 2	BIT – ST	634	Unit choice for retirement pending. Larger MW shown.
Total Retirements			**634**	
New Units				
2022	Seminole CC Facility	NG – CC	1,099	Docket No. 20170266-EC
2030	Unnamed Reciprocating Unit	NG – IC	92	
Total New Units			**1,191**	
Net Additions			**557**	

Source: 2021 Ten-Year Site Plan

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility which files a Ten-Year Site Plan. The utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2021 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

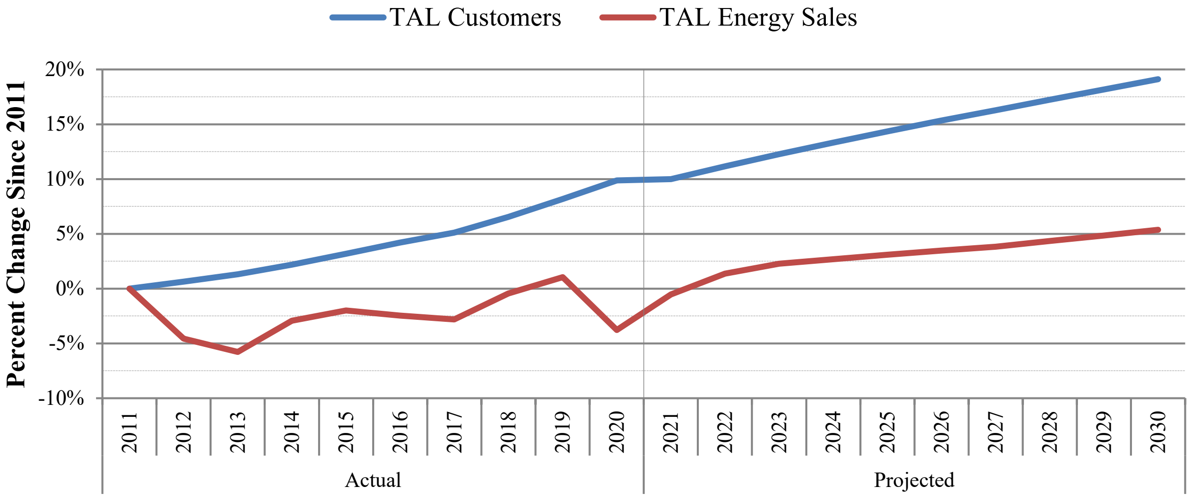
In 2020, TAL had approximately 125,478 customers and annual retail energy sales of 2,607 GWh or approximately 1.1 percent of Florida's annual retail energy sales. Figure 47 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2011. Over the last 10 years, TAL's customer base has increased by 9.86 percent, while retail sales have decreased by 3.79 percent.

TAL's 2021 customer forecast reflects projected growth rates for population, household counts, employment, and average income over 2021-2031 that are comparable to those from the 2020 Ten-Year Site Plan. As a result of the expected continuation of favorable economic conditions, the utility expects its residential and commercial counts to continue growing at rates of 0.9 per cent and 1.1 percent per year, respectively.

The utility's residential electricity use per customer has been relatively stable since the end of the 2007-08 recession. Its commercial use per customer has continued to decline albeit at a slower rate, and has been particularly impacted by the COVID-19 Pandemic. This is believed to be driven primarily from the following factors: (i) increases in end use efficiency standards, particularly for HVAC systems, that have been filtering into the stock of equipment through replacements and new builds and are believed to be nearly fully diffused into the current residential stock; (ii) significant decreases in the price of electricity on TAL's system since 2009, after a period of increase of a similar magnitude resulting primarily from the run-up in the cost of natural gas preceding the opening of shale gas resources in the U.S.; and (iii) the improvement in economic conditions since the end of the 2007-08 recession.

TAL's load forecast reflects continued decreases in use per customer for the residential class, which offsets, to some degree, robust growth in residential customer counts and essentially flat growth in average use per customer for the commercial classes. The forecasted decrease in residential average use is driven partially from a greater focus of TAL's demand side management and energy efficiency programs on that class. Over the current 10-year forecast horizon, TAL is projecting an average annual growth of 0.89 percent in its customer base, and a growth of 0.64 percent in its retail energy sales.

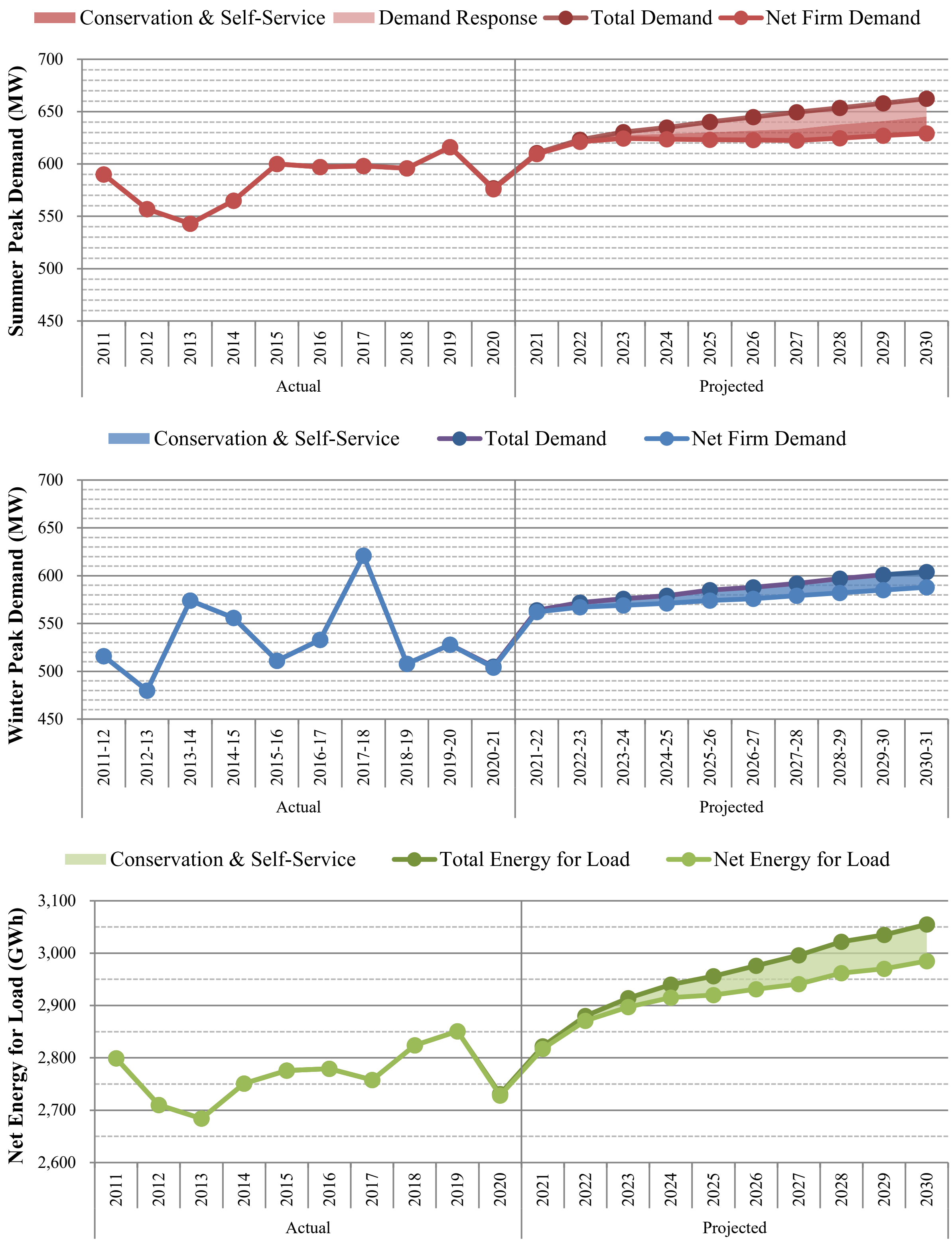
Figure 47: TAL Growth



Source: 2021 Ten-Year Site Plan

The three graphs in Figure 48 shows TAL's seasonal peak demand and net energy for load for the historic years of 2011 through 2020 and forecast years 2021 through 2030. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 48: TAL Demand and Energy Forecasts



Source: 2021 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 27 shows TAL's actual net energy for load by fuel type as of 2020 and the projected fuel mix for 2030. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities. Natural gas is anticipated to remain the primary fuel source on the system.

Table 27: TAL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2020		2030	
	GWh	%	GWh	%
Natural Gas	2666	**97.7%**	3,021	**101.2%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	113	**4.1%**	116	**3.9%**
Interchange	-51	**-1.9%**	(153)	**-5.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,729**		**2,985**	

Source: 2021 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 49 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 49: TAL Reserve Margin Forecast

Source: 2021 Ten-Year Site Plan

Generation Resources

TAL plans no unit additions or retirements during the planning period.

Attachment 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 30, 2021

TO: Braulio L. Baez, Executive Director

FROM: Penelope Buys, Engineering Specialist IV, Division of Engineering PB MR LK TB

RE: Annual Status Report on Storm Protection Plan Activities of Florida Investor-Owned Utilities

CRITICAL INFORMATION: Place on October 12, 2021 Internal Affairs Agenda. Commission approval is sought, due to the Governor and Legislature by December 1, 2021.

Pursuant to Section 366.96(10), F.S., the Commission is required to submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a status report of the utilities' storm protection activities. The attached draft satisfies the requirement of the Statute and its approval by the Commission is sought. The report is due by December 1, 2021.

Please let me or Marissa Ramos know if you have any questions or need additional information in reference to the attached document.

PB:

Attachment

cc: Deputy Executive Director – TECH (M. Futrell)
Division of Engineering (M. Ramos, L. King, T. Ballinger)

DRAFT 09-29-21

FLORIDA
PUBLIC
SERVICE
COMMISSION

Annual Status Report on Storm Protection Plan Activities of Florida Investor-Owned Utilities

As Required by Section 366.96(10), Florida Statutes

N0VEMBER 2021

Table of Contents

List of Tables

Acronyms

DEF	Duke Energy Florida, LLC
EWL	Extreme Wind Loading
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
F.S.	Florida Statutes
GULF	Gulf Power Company
IOU	Investor-Owned Electric Utility
NESC	National Electric Safety Code
OPC	Office of Public Counsel
SPP	Storm Protection Plan
SPPCRC	Storm Protection Plan Cost Recovery Clause
TECO	Tampa Electric Company

Executive Summary

In 2019, the Florida Legislature passed Senate Bill 796 to enact Section 366.96, Florida Statutes (F.S.), entitled "Storm Protection Plan Cost Recovery." Section 366.96, F.S., requires each investor-owned electric utility (IOU) to file a transmission and distribution storm protection plan (SPP) that covers the immediate 10-year planning period. The plans are required to be filed with the Commission every three years and must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. Pursuant to Section 366.96(7), F.S., the Commission shall conduct an annual proceeding to determine the utility's prudently incurred SPP costs. In addition, Section 366.96(10), F.S., requires that the Commission submit an annual report to the Governor, President of the Senate, and Speaker of the House, on the status of the utilities' storm protection activities and costs which is the purpose of this report. The Commission's rules implementing this new statute became effective on February 18, 2020.

As required by Section 366.96(10), F.S., this report includes a summary of:

- Planned and completed SPP programs and projects in the previous year
- Actual costs and rate impacts associated with completed SPP programs compared to the estimated costs and rate impacts for the same activities
- Estimated costs and rate impacts associated with SPP programs planned for the next year

Sections 3 through 6 of this report summarize the information required pursuant to Section 366.96(10) F.S. A majority of these SPP programs are a continuation of the utility's Storm Hardening Plan previously approved by the Commission.[1] Table A below provides a summary of each utility's reported estimated and actual total storm protection expenditures.[2] While most of these expenditures are being recovered through current utility base rates, all utilities are in various stages of transferring these expenditures to the annual cost recovery mechanism as contemplated by the new legislation.

Table A
Summary of SPP Costs

Utility	2020 Estimated (Millions)	2020 Actual (Millions)	2021 Estimated (Millions)
Duke Energy Florida	$242.5	$239.3	$409.3
Florida Power & Light	$964.7	$1,037.2	$1,090.6
Gulf Power Company	$32.0	$36.6	$100.8
Tampa Electric Company	$41.6	$36.9	$136.9
Totals	**$1,280.8**	**$1,350.0**	**$1,737.6**

[1] Docket No. 20180144-EI (FPL), Docket No. 2018045-EI (TECO), Docket No. 20180146-EI (DEF), Docket No. 20180147-EI (Gulf) and Docket No. 20180148-EI (FPUC), *In re: Review of 2019-2021 storm hardening plan.*
[2] The Commission is not drawing any conclusions or making any findings in this report. Any findings about current or future storm protection program cost recovery will be considered as part of a docketed proceeding and subsequent Commission order.

Section 1 – Background

In order to implement the new statute, the Commission staff held two rule development workshops, on June 25, 2019, and August 20, 2019, to obtain stakeholder comments on the draft rules. Representatives from each IOU, Florida Retail Federation, Florida Industrial Power Users Group, and the Office of Public Counsel (OPC) participated at the workshops and submitted post-workshop comments. Additionally, representatives from Florida Electric Cooperatives Association, Inc., and Florida Municipal Electric Association submitted post-workshop comments.

The Commission proposed the adoption of Rules 25-6.030, Florida Administrative Code (F.A.C), Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, at its October 3, 2019, Commission Conference.[3] However, the rules were challenged and an administrative hearing was held on December 20, 2019, at the Department of Administrative Hearings.[4] The Administrative Law Judge issued a final order on January 21, 2020, deeming the rules as valid and the rules became effective on February 18, 2020.

On April 10, 2020, Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL), Gulf Power Company (Gulf), and Tampa Electric Company (TECO) each filed for approval of their 2020-2029 Storm Protection Plans.[5] These plans are largely a continuation of the IOUs' Commission-approved Storm Hardening Plans with the addition of some newly proposed programs. Florida Public Utilities Company (FPUC) filed a Motion requesting to defer filing its SPP and refrain from participating in the Storm Protection Plan Cost Recovery Clause (SPPCRC) proceeding due to circumstances affecting the utility as a result of Hurricane Michael. The Motion was granted and FPUC continues to operate under its current Storm Hardening Plan.[6] As such, this report does not include any data from FPUC.

The Commission scheduled a formal technical hearing to be held on August 10-13, 2020, to address the four remaining dockets. However, Gulf, FPL, DEF, and TECO entered into Settlement Agreements with intervening parties prior to the hearing. On August 10, 2020, the Commission held a hearing on each Settlement Agreement and voted to approve the Agreements. The IOUs are scheduled to file their next SPPs in 2022, and FPUC will file its first SPP at that time.

On March 13, 2020, the Commission opened Docket No. 20200092-EI, to evaluate the IOU's SPP costs. A hearing was scheduled; however, prior to the hearing Gulf, FPL, DEF, and TECO entered into Settlement Agreements with intervening parties. The Commission held hearings on August

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[3] Docket No. 20190131-EU, *In re: Proposed adoption of Rule 25-6.030, F.A.C., Storm Protection Plan and Rule 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause.*
[4] Case No. 19-006137RP, *In re: Petitioner and Intervenor had standing to challenge the proposed rules, but the evidence showed that the proposed rules are not invalid exercises of delegated legislative authority.*
[5] Docket No. 20200067-EI (TECO), Docket No. 20200069-EI (DEF), Docket No. 20200070-EI (Gulf), and Docket No. 20200071-EI (FPL), *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.*
[6] Docket No. 20200068-EI, *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.*

10, September 1, and October 6, 2020, to consider the Settlement Agreements. The Commission found the Settlements fairly and reasonably balance the interests of the customers and the utility and are consistent with the stated purpose and intent of Section 366.96, F.S.[7] As such, the Commission voted to approve the Settlements and the charges went into effect on January 1, 2021. Later in 2021, FPL (in combination with Gulf), DEF and TECO each filed petitions for recovery of costs through the SPPCRC. On August 3, 2021, the Commission conducted an administrative hearing to consider these petitions. At the hearing, all parties waived post-hearing briefs and proposed stipulations on all issues identified in the Prehearing Order. The Commission voted to approve the stipulations at the conclusion of the hearing and these charges will go into effect in January 2022.[8]

Pursuant to Section 366.96(8), F.S., and Rule 25-6.031, F.A.C., SPP costs that are being recovered through the SPPCRC cannot be recovered through base rates or any other cost recovery method. On January 14, 2021, DEF filed a petition to approve a settlement with the OPC, which included moving certain SPP costs from base rates to the SPPCRC. The Commission approved that Settlement on June 4, 2021.[9] FPL,[10] Gulf,[11] and TECO[12] filed rate cases in 2021 which includes the transfer of costs from base rates to the SPPCRC for their SPP programs. The Utilities entered into Settlement Agreements with intervening parties for each of the pending rate case proceedings. Technical hearings for these utilities were held during the fall of 2021 and the Commission is scheduled to make a final decision on these dockets by the end of the year.

[7] Order Nos. PSC-2020-0293-AS-EI (TECO), issued August 28, 2020; PSC-2020-0409-S-EI (FPL/Gulf), issued October 27, 2020; PSC-2020-0410-AS-EI (DEF), issued October 27, 2020, in Docket No. 20200092-EI, *In re: Storm Protection Plan Cost Recovery Clause.*
[8] Order No. PSC-2020-0410-AS-EI, issued October 27, 2020, in Docket No. 20200092-EI, *In re: Storm Protection Plan Cost Recovery Clause.*
[9] Docket No. 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*
[10] Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company*.
[11] Ibid
[12] Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company*.

Section 2 - Summary of Filings

On June 1, 2021, DEF, FPL, Gulf, and TECO filed their annual status reports regarding their SPP programs.[13] As required by Section 366.96(10), F.S., these status reports include:

- A description of all planned and completed SPP programs and projects in 2020
- Actual costs and rate impacts associated with completed SPP programs compared to the estimated costs and rate impacts for the same activities
- Estimated costs and rate impacts associated with SPP programs planned for 2021

Each section below contains a brief description of each utility's SPP programs. A majority of these programs are a continuation of the utility's Storm Hardening Plan previously approved by the Commission. The tables contained within each section summarize the information required pursuant to Section 366.96(10), F.S. Additional details of the programs are also contained in each utility's annual status report and its filings in the annual SPPCRC proceeding.

[13] http://www.floridapsc.com/ElectricNaturalGas/StormProtectionPlans Annual Status Reports

Section 3 - Duke Energy Florida, LLC

Program Descriptions

Below are the programs that DEF implemented in 2020 or will implement in 2021. A majority of these programs are a continuation of DEF's Storm Hardening Plan. Further details of the programs are in DEF's SPP [14] or its annual SPP report.[15]

Distribution Self-Optimizing Grid

This program utilizes automated switching which allows most circuits to be restored from alternate sources. In addition, the program provides segmentation such that the distribution circuits have much smaller line segments, thus reducing the number of customers that are affected by outages.

Distribution Targeted Underground

Existing overhead distribution lines are converted to underground in order to reduce tree and debris-related outages in heavily vegetated neighborhoods. DEF selects and prioritizes locations based on a ten-year reliability assessment and outage history.

Distribution Deteriorated Conductor

The primary purpose of this program is to replace overhead conductors that are prone to outages due to brittle composition, small load capacity, and reduced connection quality. The selected areas will have all of the copper and smaller aluminum conductors brought up to the current aluminum equivalent. In addition, poles, transformers, other primary equipment, and vegetation will be brought up to DEF's current standards.

Distribution Pole Replacements and Inspections

DEF inspects wood poles on an eight-year cycle to determine the extent of pole decay and any associated loss of strength. The information gathered from the inspections is used to determine if the pole needs to be replaced or if treatment and reinforcement will extend the life of the pole. DEF completes a loading analysis on joint-use poles in its system over an eight-year cycle.

Distribution Feeder Hardening

By incorporating pole inspection and replacement activities, existing feeder circuits can be strengthened to better withstand extreme weather events. This includes strengthening or replacing structures, updating basic insulation levels and conductors to current standards, and relocating difficult to access facilities. All new structures will meet the National Electric Safety Code (NESC) 250C extreme wind load standard.

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[14] Docket No. 20200069-EI, *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.*

[15] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Duke%20Energy%20Florida,%20Inc.%20SPP%20Annual%20Status%20Report.pdf

Distribution Submersible Underground

Underground facilities that are prone to storm surge will be converted to submersible lines and equipment. In some cases, the pad mounted equipment is placed on elevated structures, which raises the equipment two to four feet above grade, to mitigate potential flood impacts.

Distribution Vegetation Management

The program consists of routine maintenance trimming, hazard tree removal, herbicide applications, vine removal, customer requested work, and right-of-way brush mowing. DEF trims its feeders on a three-year cycle and trims its laterals on a five-year cycle.

Transmission Pole/Tower Inspections

Ground-line inspections determine the extent of pole decay and any associated loss of strength. The transmission wood poles are inspected on a four-year cycle and the transmission non-wooden poles and towers are inspected on a six-year cycle.

Transmission Pole Replacements

This program's activities are based on the results of the inspections of transmission wood poles. These inspections determine the extent of pole decay and any associated loss of strength. The information gathered from the inspections is used to determine pole replacements or pole treatments.

Transmission Tower Upgrades

This program focuses on the replacement of metal towers that failed during Hurricane Irma. In addition, towers will be inspected by ground and drone. This program will strengthen towers by eliminating damage from corrosion.

Transmission Overhead Ground Wire

This program targets lines to improve lightning protection. The program prioritizes the replacement of deteriorated overhead ground wires by targeting lines with frequent lightning events, outage histories, structure design types, overhead ground wire materials, and inspection results.

Transmission Cathodic Protection

This program mitigates active ground level corrosion on the steel lattice tower system. This will be done by installing passive cathodic protection systems comprised of anodes on each leg of the lattice towers. The anodes serve as sacrificial assets that corrode in place of the structural steel, preventing loss of structure strength due to corrosion.

Transmission Substation Hardening

The replacement of electro-mechanical relays with electronic relays is designed to support rapid restoration. Electronic relays are equipped with communication capabilities and microprocessor technology, which enables a quicker recovery from events. Relay upgrades will be matched with breaker replacements when feasible.

Transmission Vegetation Management

DEF trims its transmission system on a three to six-year cycle in order to minimize vegetation-related interruptions and ensures adequate conductor-to-vegetation clearances. The program consists of danger tree identification and mitigation, reactive work, herbicide, mowing, and hand cutting brush management.

Table 3-1 provides a list of the projects and activities planned and completed for 2020 and the projects and activities planned for 2021. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2020 and the estimated costs for 2021.

Table 3-1
DEF's SPP Projects and Activities Planned and Completed for 2020 and 2021

Program name	Projects/ Activities Planned for 2020	Estimated Cost for 2020 (Millions)	Projects/ Activities Completed in 2020	Actual Cost for 2020 (Millions)	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)
Dist. Self-Optimizing Grid	156	$ 56.5	410	$ 66.4	741	$ 75.3
Dist. Targeted Underground	214	$ 42.5	205	$ 29.4	204	$ 65.2
Dist. Deteriorated Conductor	24	$ 14.6	22	$ 13.5	17	$ 28.2
Dist. Pole Inspections (poles)	100,000	$ 3.9	86,357	$ 4.1	153,573	$ 6.3
Dist. Pole Replacements (poles)	2,668	$ 23.6	2,696	$ 18.3	3,433	$ 25.1
Dist. Feeder Hardening	0	$ 0.0	0	$ 0.0	17	$ 59.5
Dist. Submersible Underground	1	$ 0.3	0	$ 0.0	0	$ 0.0
Dist. Vegetation Management (miles)	5,208	$ 45.9	5,322	$ 45.4	4,361	$ 46.5
Trans. Pole/Tower Inspections/Drone Inspections	10,959	$ 0.4	12,438	$ 0.4	13,900	$ 0.5
Trans. Pole Replacements (poles)	642	$ 34.3	766	$ 39.5	1,495	$ 69.7
Trans. Tower Upgrades	1	$ 0.8	1	$ 0.8	3	$ 1.8
Trans. Overhead Ground Wire	3	$ 1.8	4	$ 0.6	2	$ 1.5
Trans. Cathodic Protection	2	$ 0.4	0*	$ 0.0	3	$ 1.2
Trans. Substation Hardening	5	$ 5.0	5	$ 4.9	15	$ 5.5
Trans. Vegetation Management (miles)	380	$ 12.5	252	$ 16.0	335	$ 23.0
Totals		**$242.5**		**$239.3**		**$409.3**

Source: DEF's 2020 SPP Annual Report and responses to staff's data requests.

*Note: The two Transmission Cathodic Protection projects were deferred to 2021 due to a contractor issue.

Note: Trans = Transmission Dist. = Distribution.

Table 3-2 provides the typical residential customer's bill impact for the implementation of DEF's SPP programs. These values represent the total costs of DEF's SPP activities, some of which are recovered through base rates and others through the SPPCRC. Once the costs of the SPP projects are moved to the SPPCRC, DEF's base rates will be reduced accordingly.

Table 3-2
DEF's Actual and Projected Bill Impacts (in dollars)

2020 Estimated		2020 Actual		2021 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$242.5	$2.11	$239.3	$2.05	$409.3	$2.64

Source: DEF's 2020 SPP Annual Report and responses to staff's data requests.

Section 4 - Florida Power & Light

Program Descriptions

Below are the programs that FPL implemented in 2020. A majority of these programs are a continuation of FPL's Storm Hardening Plan. Further details of the programs are in FPL's SPP[16] or in its annual SPP report.[17]

Pole Inspection – Distribution Program

This program includes an eight-year pole inspection cycle for all distribution wood poles. FPL established nine inspection zones to ensure inspection coverage throughout its service area. In addition, joint-use audits are conducted as part of the Pole Inspection - Distribution Program.

Structure/Other Equipment Inspections – Transmission Program

This program ensures that transmission wood, steel, and concrete structures are visually inspected from the ground on an annual basis. Transmission circuits and substations will be inspected on a six-year cycle. Climbing or bucket truck inspections on wood structures will be on a six-year cycle and climbing or bucket truck inspections on steel and concrete structures will be on a ten-year cycle.

Feeder Hardening Extreme Wind Loading – Distribution Program

Feeders are hardened as a result of FPL's Priority Feeder Initiative which is a reliability program that targets feeders experiencing the highest number of interruptions and/or customers interrupted. This includes FPL's initiative of design and construction practices to meet the NESC Extreme Wind Loading (EWL) criteria.

Lateral Hardening (Undergrounding) – Distribution Program

FPL originally started this program as a pilot program in 2018 and has continued the program as part of its SPP. This program targets certain overhead laterals, which were impacted by recent storms and have a history of vegetation-related outages and other reliability issues, for conversion from overhead to underground.

Wood Structures Hardening (Replacing) – Transmission Program

This program replaces all wood transmission structures with steel or concrete structures. As of year-end 2019, FPL reported that 96 percent of its transmission system is steel or concrete; therefore, less than 2,900 (4 percent) wood transmission structures need to be replaced.

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[16] Docket No. 20200071-EI, *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.*

[17] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Florida%20Power%20and%20Light%20Company%20SPP%20Annual%20Status%20Report.pdf

Vegetation Management – Distribution Program

To maintain current cycles, FPL plans to trim, on average, approximately 11,400 miles of feeders and 3,800 miles of laterals, which is consistent with historically recorded miles. This program includes a three-year trim cycle for feeders, mid-year targeted trim maintenance cycle for certain feeders, six-year trim cycle for laterals, and continued customer education through FPL's Right Tree, Right Place initiative.

Vegetation Management – Transmission Program

FPL plans to inspect and maintain, on average, approximately 7,000 miles of its transmission lines annually, which is comparable to the historically maintained miles. This program includes inspecting the rights-of-way of transmission infrastructure, documenting vegetation inspection results and findings, and prescribing and executing a work plan.

Substation Storm Surge/Flood Mitigation Program

The Substation Storm Surge/Flood Mitigation program is a new program included in FPL's SPP. Damage to substations that are susceptible to storm surge and flooding during extreme weather events can be eliminated by raising the equipment at certain substations above flood level and construct flood protection walls around other substations.

Table 4-1 provides a list of the projects and activities planned and completed for 2020 and the projects and activities planned for 2021. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2020 and the estimated costs for 2021.

Table 4-1
FPL's SPP Projects and Activities Planned and Completed for 2020 and 2021

Program Name	Projects/ Activities Planned for 2020	Estimated Cost for 2020 (Millions)	Projects/ Activities Completed in 2020	Actual Cost for 2020 (Millions)	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)
Pole Inspection – Dist. (poles)	150,000	$ 54.5	147,003	$ 38.5	150,000	$ 57.9
Structure/Other Equipment Inspections – Trans.	68,000	$ 35.8	68,962	$ 28.4	69,000	$ 32.2
Feeder Hardening (Extreme Wind Loading) – Dist.	350	$628.1	302	$ 681.7	350	$ 664.9
Lateral Hardening (Undergrounding) – Dist.	230	$120.4	216	$ 129.3	350	$ 212.5
Wood Structures Hardening (Replacing) – Trans.	1,100	$ 52.9	942	$ 86.0	822	$ 42.9
Vegetation Management – Dist. (miles)	15,200	$ 61.1	15,269	$ 60.7	15,200	$ 61.3
Vegetation Management – Trans. (miles)	7,000	$ 8.9	7,278	$ 9.4	7,000	$ 8.9
Substation Storm Surge/Flood Mitigation	1	$ 3.0	0*	$ 3.2	10*	$ 10.0
Totals		**$964.7**		**$1,037.2**		**$1,090.6**

Source: FPL's 2020 SPP Annual Report and responses to staff's data requests.

*Note: FPL began working on eight substations in 2020 and will continue to work on them in 2021 in addition to two other substation being initiated in 2021.

Note: Trans = Transmission Dist. = Distribution.

Table 4-2 provides the typical residential customer's bill impact for the implementation of FPL's SPP programs. These values represent the total costs of FPL's SPP activities, some of which are recovered through base rates and others through the SPPCRC. Once the costs of the SPP projects are moved to the SPPCRC, FPL's base rates will be reduced accordingly.

Table 4-2
FPL's Actual and Projected Bill Impacts (in dollars)

2020 Estimated		2020 Actual		2021 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$964.7	$1.30	$1,037.2	$1.29	$1,090.6	$1.36

Source: FPL's 2020 SPP Annual Report and responses to staff's data requests.

Section 5 - Gulf Power Company

Program Descriptions

Below are the programs that Gulf implemented in 2020. A majority of these programs are a continuation of Gulf's Strom Hardening Plan. Further details of the programs are in Gulf's SPP[18] or in its annual SPP report.[19]

Distribution Inspection Program

Distribution inspections consist of feeder patrols, infrared patrols, wood pole inspections and wood pole remediation and/or replacement. This inspection program aims to achieve reductions of wood pole failures, fewer storm-related outages, and a reduction in storm restoration time and costs. As part of this program, Gulf performs load analysis on its joint-use poles.

Transmission Inspection Program

The inspections of distribution and transmission substations and structures is achieved through a prescribed set of processes and procedures. This program includes conducting annual aerial patrols to inspect transmission lines, structures, and circuits.

Distribution Feeder Hardening Program

This program includes hardening options such as applying EWL for design and construction, storm guying, equipment relocation, and utilization of distribution automation. The utility has approximately 269 feeders remaining to be hardened and expects to complete approximately 12 to 18 feeder projects annually.

Distribution Hardening Lateral Undergrounding Program

The Lateral Undergrounding program is a new program included in Gulf's SPP. The program targets certain overhead laterals impacted by recent storms and a history of vegetation-related outages and other reliability issues.

Transmission Hardening Program

The three components of this program are: substation flood monitoring and hardening, transmission and substation resiliency, and transmission structure replacement. Projects contained within this program include flood monitoring on vulnerable substations, reviewing switch house construction standards, and replacement of transmission wood structures and poles.

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[18] Docket No. 20200070-EI, *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.*

[19] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Gulf%20Power%20Company%20SPP%20Annual%20Status%20Report.pdf

Vegetation Management – Distribution Program

Gulf will clear vegetation in areas surrounding its distribution facilities and equipment. The vegetation management cycles are as follows: three-year cycle for feeders, mid-year cycle inspections and maintenance for feeders, and four-year cycle for laterals. Additionally, this program encompasses Gulf's Right Tree, Right Place initiative, which aims to educate customers on choosing the appropriate locations for planting trees in efforts to prevent future outages.

Vegetation Management – Transmission Program

The key elements of this program are vegetation management on right-of-way ground floors, annual ground inspections of transmission right-of-ways, document vegetation inspections results and findings, and prescribe a work plan and execute the work plan. Gulf plans to maintain, on average, approximately 1,675 miles of Gulf's transmission system on an annual basis.

Table 5-1 provides a list of the projects and activities planned and completed for 2020 and the projects and activities planned for 2021. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2020 and the estimated costs for 2021.

Table 5-1
Gulf's SPP Projects and Activities Planned and Completed for 2020 and 2021

Program name	Projects/ Activities Planned for 2020	Estimated Cost for 2020 (Millions)	Projects/ Activities Completed in 2020	Actual Cost for 2020 (Millions)	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)
Dist. Inspection (poles)	26,000	$ 3.4	25,542	$ 4.6	26,000	$ 3.0
Trans. Inspection	2,400	$ 3.5	2,275	$ 0.7	2,400	$ 3.6
Dist. Feeder Hardening	6*	$12.3	0	$16.1	21*	$ 35.9
Dist. Hardening Lateral Undergrounding	0**	$ 0.0	0	$ 0.0	8	$ 5.2
Trans. Hardening	83	$ 5.3	74	$ 8.3	386	$ 45.5
Vegetation Management – Dist. (miles)	2,000	$ 5.0	1,765	$ 4.8	2,000	$ 4.7
Vegetation Management – Trans. (miles)	1,675	$ 2.5	1,675	$ 2.1	1,675	$ 2.9
Totals		**$32.0**		**$36.6**		**$100.8**

Source: Gulf's 2020 SPP Annual Report and responses to staff's data requests.

*Note: The six feeders were started in 2020 and will be finalized during first quarter of 2021.

**Note: In 2020, Gulf was in the initial planning and research phase of this program. The program began during the fourth quarter of 2020.

Note: Trans = Transmission Dist. = Distribution.

Table 5-2 provides the typical residential customer's bill impact for the implementation of Gulf's SPP programs. These values represent the total costs of Gulf's SPP activities, some of which are recovered through base rates and others through the SPPCRC. Once the costs of the SPP projects are moved to the SPPCRC, Gulf's base rates will be reduced accordingly.

Table 5-2
Gulf's Actual and Projected Bill Impacts (in dollars)

2020 Estimated		2020 Actual		2021 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$32.0	$1.11	$36.6	$0.98	$100.8	$1.44

Source: Gulf's 2020 SPP Annual Report and responses to staff's data requests.

Section 6 - Tampa Electric Company

Program Descriptions

Below are the programs that TECO implemented in 2020. A majority of these programs are a continuation from TECO's Strom Hardening Plan. Further details of the programs are in TECO's SPP[20] or in its annual SPP report.[21]

Distribution Lateral Undergrounding

TECO's Distribution Lateral Undergrounding program is a new program included in its SPP that strategically undergrounds existing overhead laterals. The primary factor in prioritizing laterals to be underground is based on reliability performance during extreme weather events.

Vegetation Management

TECO's distribution and transmission vegetation management activities are both addressed in this program. TECO's distribution tree trimming program includes circuit tree trimming activities, mid-cycle trimming activities, customer requested work, and work orders associated with circuit improvement processes. TECO's distribution system is on a four-year cycle and the transmission system is on three-year cycle.

Transmission Asset Upgrades

TECO plans to replace its remaining transmission wood poles with non-wood material. This is a continuation of TECO's existing pole replacement program, which includes replacing poles based on preventative, corrective or project-driven assessments.

Substation Extreme Weather Hardening

Hardening existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events is a new program included in TECO's SPP. No projects were planned or completed for 2020 under this program as TECO is still conducting studies on the substations.

Distribution Overhead Feeder Hardening

TECO's distribution system will be hardened to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events by increasing the resiliency and sectionalizing capabilities of the system.

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[20] Docket No. 20200067-EI, *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.*

[21] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Tampa%20Electric%20Company%20SPP%20Annual%20Status%20Report.pdf

Transmission Access Enhancements

In order to have continuous access to its transmission facilities for restoration, TECO implemented this new program in its SPP to maintain the access roads and bridges leading to its facilities. TECO did not plan or complete any projects in 2020. However, the utility plans to complete 20 road projects and 17 bridge projects during the 2020-2029 time frame.

Infrastructure Inspections

TECO's distribution wood pole inspections and transmission structure inspections, and the joint use pole attachment audit are combined into one program. The distribution wood pole inspections are on an eight-year cycle program consisting of visual inspections, sound and bore inspections, and excavations at least 18 inches below ground line. The transmission structure inspections include a range of inspections from ground to aerial infrared patrols with a range of cycles from annual to eight years. The joint use pole attachment audit is a comprehensive loading analysis to ensure TECO's poles with joint use attachments are not overloaded and meet the NESC standards. This audit will be performed every four to five years.

Table 6-1 provides a list of the projects and activities planned and completed for 2020 and the projects and activities planned for 2021. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2020 and the estimated costs for 2021.

Table 6-1
TECO's SPP Projects and Activities Planned and Completed for 2020 and 2021

Program name	Projects/ Activities Planned for 2020	Estimated Cost for 2020 (Millions)	Projects/ Activities Completed in 2020	Actual Cost for 2020 (Millions)	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)
Dist. Lateral Undergrounding	139	$ 8.0	1	$ 7.2	520	$ 79.5
Dist. Vegetation Management (miles)	1,965	$16.5	2,071	$17.0	2,314	$ 19.8
Trans. Vegetation Management (miles)	594	$ 2.6	518	$ 1.8	554	$ 3.7
Trans. Asset Upgrades (poles)	305	$ 5.6	296	$ 5.0	46	$ 15.2
Substation Extreme Weather Hardening*	0	$ 0.0	0	$ 0.0	0	$ 0.3
Dist. Overhead Feeder Hardening	1,175	$ 6.7	216	$ 3.8	33	$ 15.4
Trans. Access Enhancements	0	$ 0.0	0	$ 0.0	18	$ 1.4
Dist. Infrastructure Inspections (pole and structures)	22,500	$ 0.7	25,606	$ 0.2	19,650	$ 0.6
Trans. Infrastructure Inspections (poles and structures)	3,934	$ 0.5	4,262	$ 0.3	4,478	$ 0.6
SPP Planning & Common	N/A	$ 1.0	N/A	$ 1.6	N/A	$ 0.4
Totals		**$41.6**		**$36.9**		**$136.9**

Source: TECO's 2020 SPP, 2020 SPP Annual Report, 2021 SPPCRC True-up, and responses to staff's data requests.

*Note: TECO is performing a study to evaluate hardening options for 24 existing transmission and distribution substations.

Note: Trans = Transmission Dist. = Distribution.

Table 6-2 provides the typical residential customer's bill impact for the implementation of TECO's SPP programs. These values represent the total costs of TECO's SPP activities, some of which are recovered through base rates and others through the SPPCRC. Once the costs of the SPP projects are moved to the SPPCRC, TECO's base rates will be reduced accordingly.

Table 6-2
TECO's Actual and Projected Bill Impacts (in dollars)

2020 Estimated		2020 Actual		2021 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$41.6	$1.50	$36.9	$1.03	$136.9	$2.39

Source: TECO's 2020 SPP Annual Report and responses to staff's data requests.

III. Supplemental Materials for Internal Affairs

Note: The records reflect that there were no supplemental materials provided to the Commission during this Internal Affairs meeting.

IV. Transcript

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PROCEEDINGS: INTERNAL AFFAIRS

COMMISSIONERS PARTICIPATING: CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER ANDREW GILES FAY
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Tuesday, October 12, 2021

TIME: Commenced: 10:15 a.m.
Concluded: 10:23 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: ANDREA KOMARIDIS WRAY
Court Reporter and
Notary Public in and for
the State of Florida at Large

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
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P R O C E E D I N G S

CHAIRMAN CLARK: All right. Good morning, once again. We'll call the Internal Affairs meeting to order.

We're going to begin today with a draft review of the 2021 draft ten-year site plan.

Mr. Phillips, I think you're going to introduce this item for us.

MR. PHILLIPS: Good afternoon, Commissioners. Donald Phillips with Commission staff.

Item No. 1 is the draft review of the 2021 ten-year site plans of Florida's electric utilities. This year's review is in the same format and contains similar content as last year's review.

The report shows similar trends to last year's, with fuel projection showing that natural-gas generation will continue to provide a majority of net energy load through 2030; however, solar resources are projected to increase considerably, with over 15,000 megawatts of new planned solar, up from 13,000 megawatts of last year.

Florida utilities also plan to expand battery-storage capacity with a projection of over 1,050 megawatts of battery storage.

At this time, staff seeks the Commission's approval of the draft review of the 2021 ten-year site plans, which could find each utility's plan suitable for planning purposes and administrative leave to correct scrivener's errors and any other non-material changes prior to publication of the final version.

If the Commission approves the draft, review and attached comments would be provided to the Department of Environmental Protection for consideration in future need-determination proceedings, and the Department of Agriculture and Consumer Services regarding fuel and load forecasts.

Staff is available for any questions. Thank you.

CHAIRMAN CLARK: All right. Thank you, Mr. Phillips.

Commissioners, questions, comments regarding the draft plan? No one. Really. Okay.

All right. I will entertain a motion to approve the draft plan.

Commissioner La Rosa.

COMMISSIONER La ROSA: Chairman, motion to approve the draft plan.

CHAIRMAN CLARK: Motion to approve.

COMMISSIONER FAY: Second.

CHAIRMAN CLARK: Second from Commissioner Fay. Any discussion?

On the plan, all in favor, say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?

Motion carries. Draft plan is approved.

Thank you very much, Mr. Phillips.

Next item is the status report on the utility storm-protection activities. And I'm not sure who is going to introduce this item -- Ms. Buys.

MS. BUYS: Good morning. I'm Penelope Buys with engineering.

Item No. 2 is the draft annual -- draft report on the storm-protection activities of the Florida investor-owned utilities. In 2019, the Florida Legislature passed Senate Bill 796 -- 796 to enact Section 366.96 of the Florida Statutes entitled "The Storm Protection Plan Cost Recovery".

The statute requires, among other things, that each IOU file a transmission and distribution storm-protection plan that covers the immediate ten-year planning period.

Each plan must explain a systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.

Pursuant to Subsection 10 of the statute, the Commission is required to submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives the annual status report of the IOUs' storm-protection activities.

This is the first year the status report is being submitted and is due by December 1st. Staff believes the status report contains the information required by statute and notes that the Commission is not drawing any conclusions or making any findings in this report.

Any findings about the current or future storm-protection program cost recovery will be considered as part of a docketed proceeding and subsequent Commission order.

In addition, staff would like to make a note to a correction in Secti- -- Section 1, in the background that was sent to your offices. This correction clarifies the docket in which the Commission granted TECO's re- -- request to move certain SPP costs out of base rates to the SPP clause.

Staff is seeking your approval on the report as well as administrative authority to make minor edits, if needed.

Staff is available for any questions. Thank you.

CHAIRMAN CLARK: All right. Thank you very much, Ms. Buys.

Commissioners, do you have any questions on the storm-protection plan?

Commissioner La Rosa.

COMMISSIONER La ROSA: Thank you, Chairman.

Obviously, we're -- we're very new in this process, this being the first time before us. Staff did a great job of explaining things to me in -- in some detail.

One of my biggest concerns was -- (technical interruption) --

CHAIRMAN CLARK: (Inaudible.)

COMMISSIONER La ROSA: I knew it -- I knew it had to be something, so I guess that's what it was.

Staff did a great job of explaining things to me in detail.

One of the things that I was concerned with was, this being the first time, how smooth the process was as far as reporting. And I'm very curious to see how things continue, of course, once we have a comparison as time comes with this and additional reporting is done.

But I think this is certainly interesting. I think at the time that this was passed by the Legislature -- of course, we had a major hurricane come through the state of Florida. And I think this is a good reaction to -- to what we've seen and what the issues were -- were then, but overall, very satisfied with what's before us.

CHAIRMAN CLARK: Thank you, Commissioner La Rosa.

Other Commissioners have questions or comments?

All right. I'll entertain your motion to approve the draft plan.

COMMISSIONER La ROSA: Chairman, motion to approve.

CHAIRMAN CLARK: Motion to approve.

Second?

COMMISSIONER FAY: Second.

CHAIRMAN CLARK: Second. Any discussion?

On the motion, all in favor, say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?
Motion carries.
Thank you very much, Ms. Buys.
Next on the agenda, general counsel's report. Mr. Hetrick.
MR. HETRICK: No -- no report, Mr. Chair.
CHAIRMAN CLARK: Executive director.
MR. BAEZ: Thank you, Mr. Chairman. Good morning, Commissioners.
Quick updates, as committee weeks are starting to get more frequent in the ramp-up to the next session, which begins in January. The Commission staff has been invited already a couple of times -- one of those meetings being to present relative to our input on the EV master plan. Cayce has been quite busy, as -- as has our legislative staff, Kaley and Katherine.
No file -- no bills have been filed yet, but we did give a presentation last week before the House, the Transportation Infrastructure Committee, and are invited to present next week -- although, I don't have the date exactly, but I think it's Thursday -- to present on the Senate side.
A lot of questions are flying around. And, as I said, there hasn't been a bill filed yet, but

it -- it sounds like folks are asking questions along -- as a -- as an approach to that. We will keep you apprized of how the presentations and how the questions come and go.

If you want to -- if any of you all want to discuss in greater detail what the impressions are, have any questions, please let us know. We can arrange to meet with you individually.

Thanks.

CHAIRMAN CLARK: All right. Any questions, comments from the Commission?

All right. Any other matters to come before us?

Seeing none, Internal Affairs is adjourned. Thank you for being here today.

(Whereupon, the proceedings concluded at 10:23 a.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, ANDREA KOMARIDIS WRAY, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 26th day of October, 2021.

ANDREA KOMARIDIS WRAY
NOTARY PUBLIC
COMMISSION #HH 089181
EXPIRES February 9, 2025