REVIEW OF THE

2020 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA
PUBLIC
SERVICE
COMMISSION

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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 2020 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

[1] Investor-owned utilities filing 2020 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 2020 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 2020 Ten-Year Site Plan.

The 2020 Ten-Year Site Plans were filed with the Commission on April 1, 2020, and were prepared by the utilities before the onset of the COVID-19 pandemic. Consequently, these Ten-Year Site Plans do not include information with respect to any potential impacts caused by the pandemic.

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 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 2020 Ten-Year Site Plans

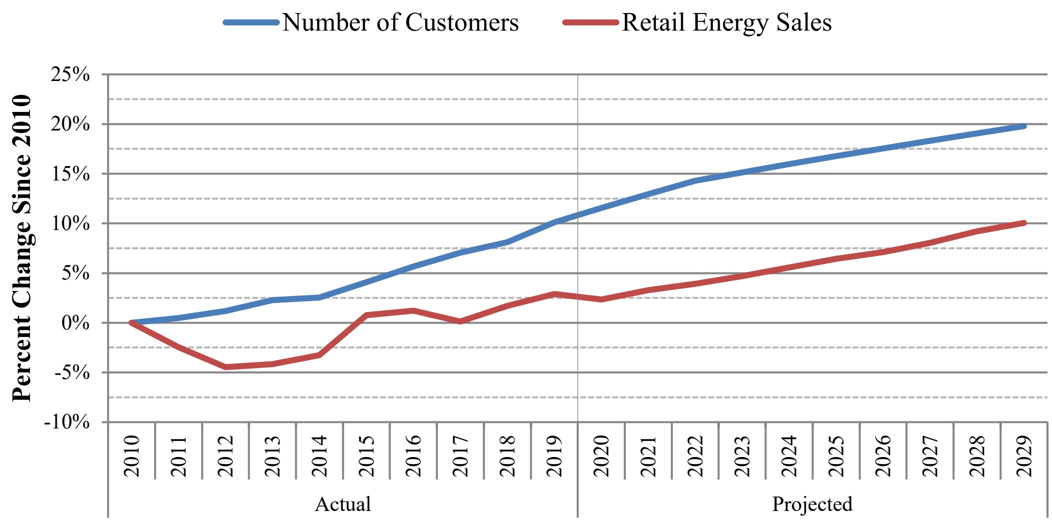
The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's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

[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.

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



Source: FRCC 2020 Regional Load and Resource Plan

Renewable Generation

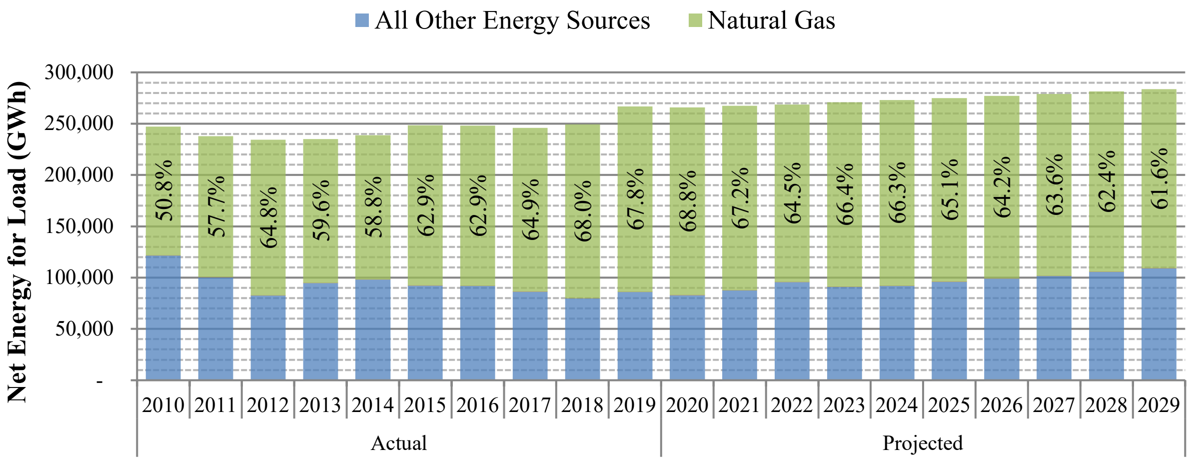
Renewable resources continue to expand in Florida, with approximately 4,254 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar, municipal solid waste, and biomass. These make up approximately 85 percent of Florida's renewables. Notably, Florida electric customers had installed 514 MW of demand-side renewable capacity by the end of 2019, resulting in an increase of 62 percent from 2018.

Florida's total renewable resources are expected to increase by an estimated 13,212 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar photovoltaic (PV) generation accounts for all of this increase. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. Reasons given for these additions are the continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained during solar demonstration projects. 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.

Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,744 MW of traditional generation over the planning horizon. Natural gas electric generation, as a percent of net energy for load (NEL), is expected to decline slightly over the planning horizon, with usage in 2029 anticipated to be approximately 62 percent of NEL. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida.

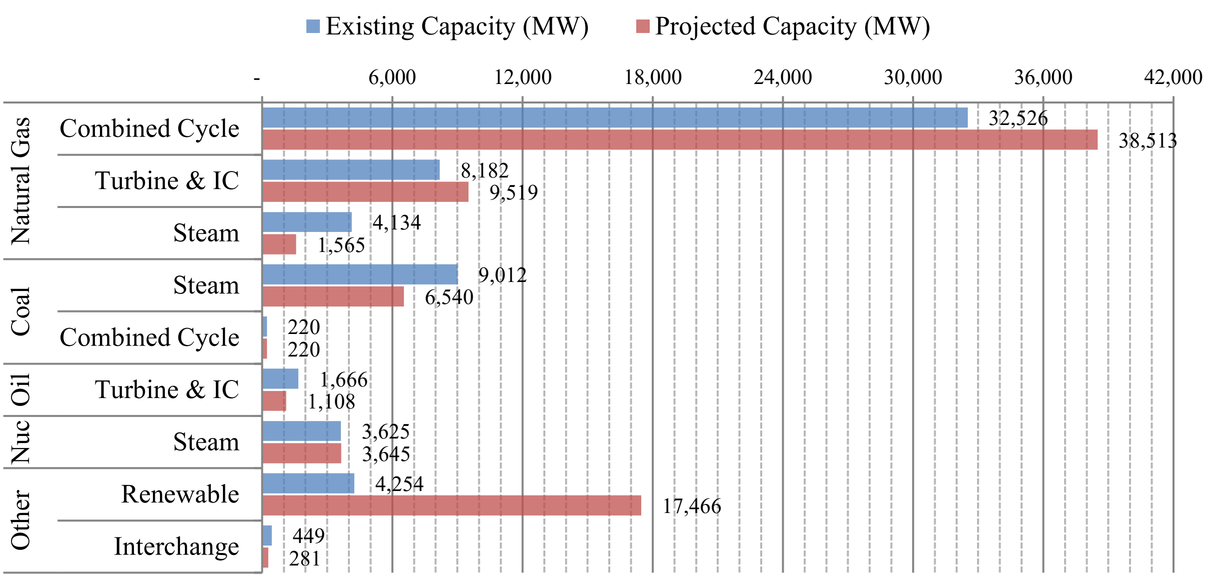
Figure 2: State of Florida - Natural Gas Generation



Source: FRCC 2011-2020 Regional Load and Resource Plan

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2020 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 2020 Regional Load and Resource Plan & TYSP 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, on August 21, 2018, as part of its proposed Affordable Clean Energy (ACE) rule (which addresses carbon dioxide air emissions), the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. While the ACE rule has been finalized, the EPA has taken no final actions regarding the New Source Review permitting program. These and other relevant EPA actions are further discussed on pages 36 and 37. Any recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review.

Conclusion

The Commission has reviewed the 2020 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 2020 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 TYSPs 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 TYSPs. 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 TYSPs 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 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

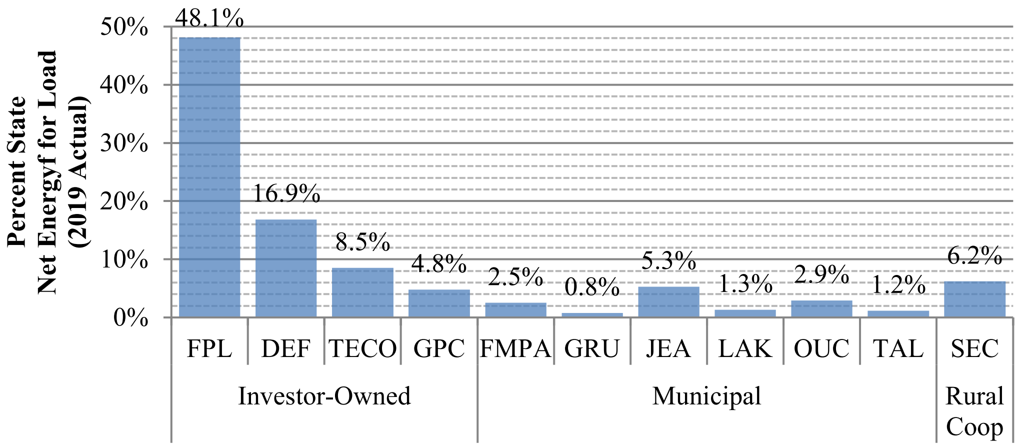
Florida is served by 57 electric utilities, including 5 investor-owned utilities, 34 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity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

In 2020, 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 2020 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 2019. 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: 2020 Ten-Year Site Plans & FRCC 2020 Regional Load and Resource Plan

Required Content

The Commission requires each reporting utility to provide information on a variety of topics. 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 18, 2020, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2020 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 FPL, GPC, TECO, the Southern Alliance for Clean Energy, and Vote Solar. Several members of the public also provided comments.

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' 2020 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

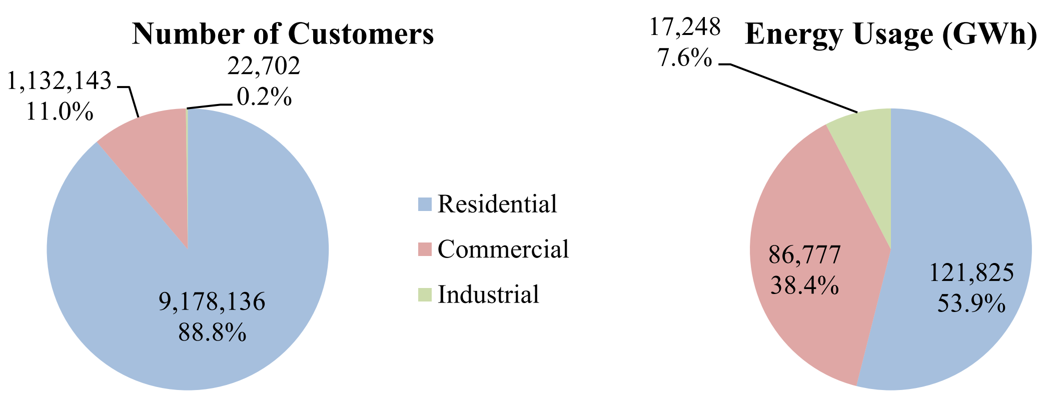
Load Forecasting

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, 2020, residential customers account for 88.8 percent of the total, followed by commercial (11.0 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 2019



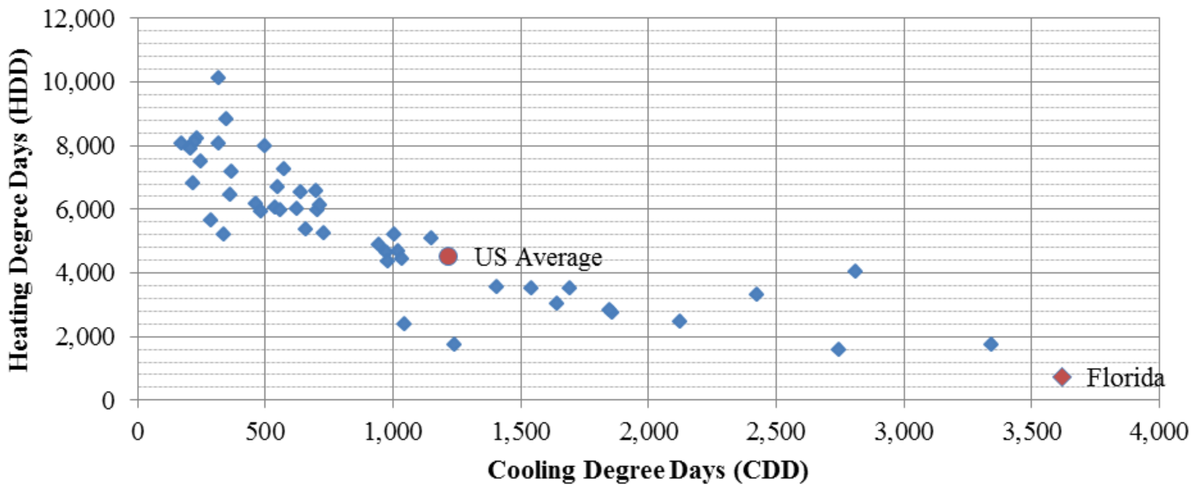
Source: FRCC 2020 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 53.9 percent of retail energy sales in 2019, compared to a national average of 38.3 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 2020 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 - Climate Data by State (Continental US)

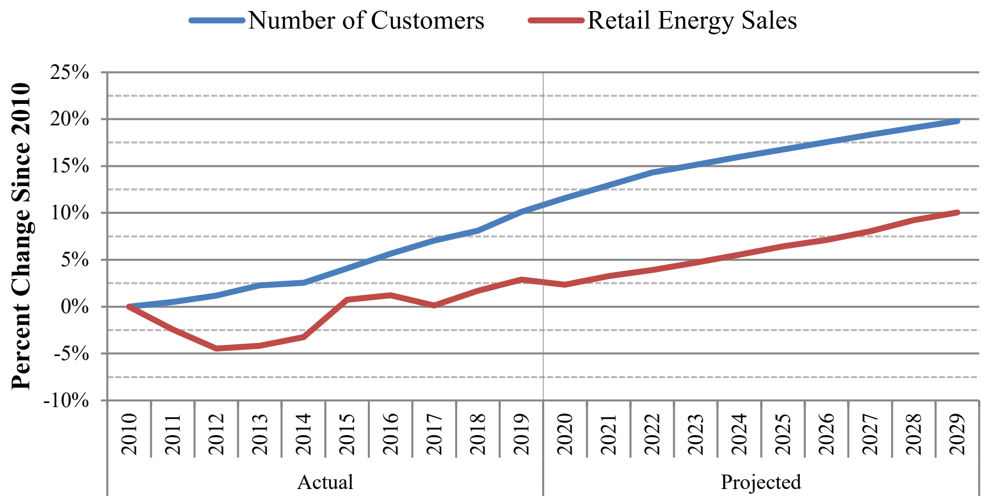


Source: National Oceanic and Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next 10-year period, Florida's retail energy sales, weather normalized, are projected to grow at 0.81 percent per year, compared to the 0.32 percent actual annual increase experienced during the 2010-2019 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 0.79 percent for the next 10-year period, compared to the 1.08 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 2020 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.

Figure 7 shows that the forecasted annual customer growth rates are expected to decelerate to some extent starting in 2023. Based on the information provided by the utilities, the projected total number of customers of FPL and GPC combined is approximately 5.7 million, or approximately 53.4 percent of the state's total retail customers in 2022. Their combined annual average customer growth rate would reach a peak at that time then start to decrease slightly for the rest of the forecast period. The projected total number of customers of DEF is approximately 1.9 million customers, or approximately 18.0 percent of the state's total retail customers in 2023. The annual average customer growth rate of DEF is expected to reach a peak in 2023 then start to decrease somewhat each year for the rest of the forecast period. Also, TECO and other utilities have each projected a reduced annual customer growth rate throughout the forecast period in their respective 2020 TYSPs, compared to the forecast presented in the 2019 TYSPs. This statewide slowdown in customer growth is largely attributed to the reduced projections of population and housing starts prepared by the vendor consultants upon which the forecasts of utilities' customer growth were developed. More details are discussed in the Utilities Perspective portion of this report.

With respect to the energy consumption per customer forecasts, FPL and GPC indicated that improvements to energy efficiency are expected to continuously play a role in the 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. The utility 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. However, DEF pointed out that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer. 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 also 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.

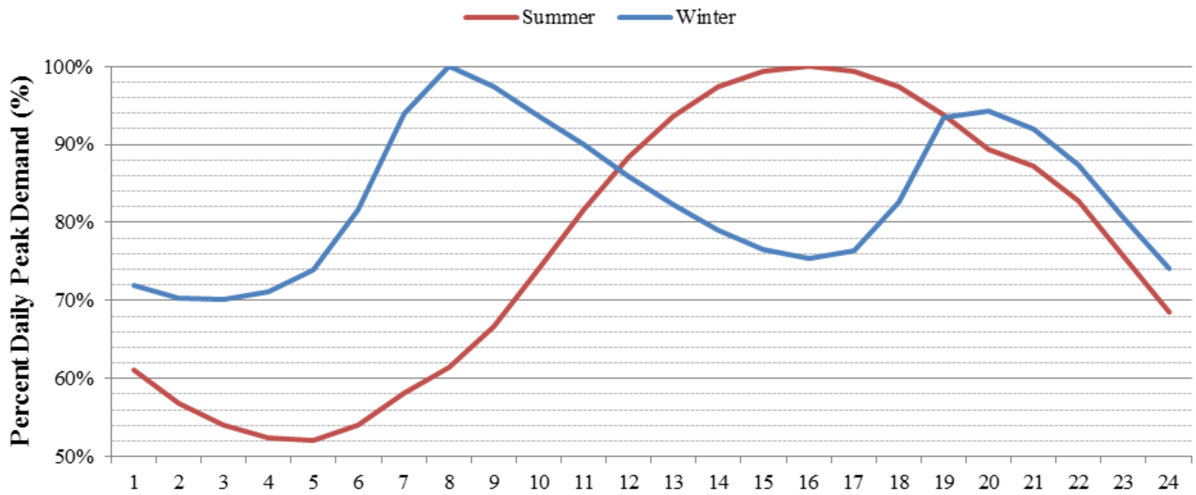
The aforementioned forecasts of customers and energy sales were developed before the onset of the COVID-19 pandemic which significantly affected the global and US economies. The magnitude of the pandemic's impact on Florida's energy industry is still highly uncertain. However, most of the TYSP Utilities have experienced negative impacts in the first half of 2020, and further reductions are expected in energy sales for 2020 through 2022 compared to the energy sales projected in the Utilities' 2020 TYSPs.

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. 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 large spike in the morning and a smaller spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

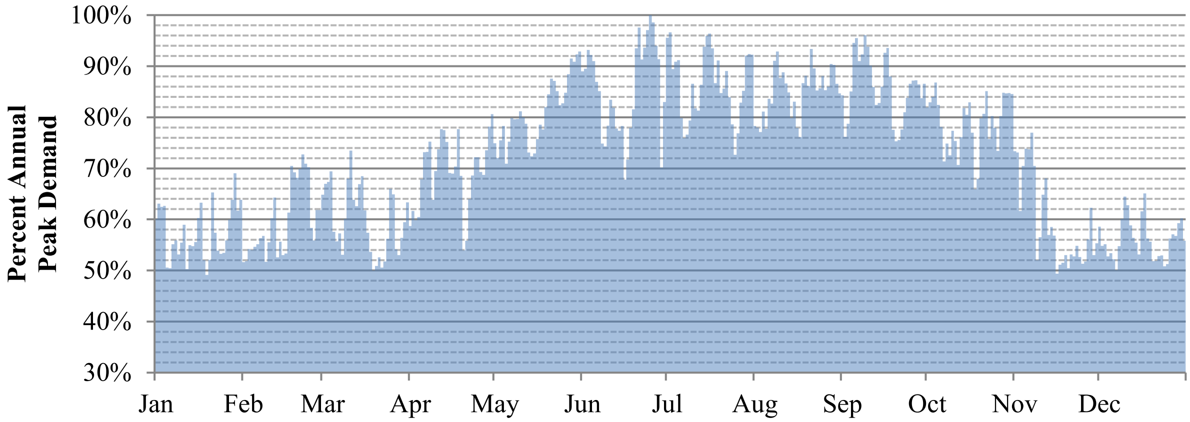


Source: TYSP Utilities' Data Responses

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 2019 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 2019 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 (2019 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 69,621 electric plug-in vehicles will be operating in Florida by the end of 2020. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 5, 2020, at 17.1 million vehicles, resulting in an approximate 0.41percent 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 646,199 electric vehicles operating within the electric service territories by the end of 2029.

[4] Florida Department of Highway Safety and Motor Vehicles January 2020 Vehicle and Vessel Reports and Statistics.

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

YEAR	FPL	DEF	TECO	GPC	GRU	JEA	TAL	TOTAL
2020	43,419	15,300	5,459	1,886	350	1,801	1,406	**69,621**
2021	55,982	21,860	6,530	2,293	409	2,115	1,420	**90,609**
2022	71,165	30,491	7,815	2,787	478	2,438	1,435	**116,608**
2023	90,926	41,025	9,321	3,387	558	2,767	1,449	**149,433**
2024	122,493	53,666	11,052	4,117	653	3,106	1,463	**196,550**
2025	161,955	69,019	13,049	5,004	755	3,456	1,478	**254,717**
2026	211,256	86,038	15,183	6,082	872	3,820	1,493	**324,744**
2027	272,823	104,722	17,456	7,393	1,009	4,196	1,508	**409,106**
2028	352,842	125,363	19,869	8,985	1,166	4,589	1,524	**514,339**
2029	456,836	148,071	22,425	10,921	1,349	4,997	1,600	**646,199**

Source: TYSP Utilities' Data Responses

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. In March 2020, the Florida Legislature passed CS/SB 7018, a bill which contains various provisions relating to essential state infrastructure, including provisions relating to development of a recommended plan for electric vehicle charging stations along Florida's highway system.[5] In June 2020, the legislation was signed by Governor DeSantis. The bill requires the Florida Department of Transportation, in consultation with the Commission and the State Energy Office, to coordinate, develop, and recommend a master plan for the development of electric vehicle charging station infrastructure along the State Highway System, due to the Governor and the Legislature by July 1, 2021. The Commission's duties in support of the development of the master plan include: projecting the deployment of electric vehicles in Florida over the next 20 years, comparing the types of electric vehicle charging stations now and in the future, considering strategies to develop this supply of charging stations, identifying regulatory structures necessary for the delivery of electricity to charging stations, and reviewing emerging technologies in the electric and alternative vehicle market, including alternative fuel sources. In addition, on July 10, 2020, Governor DeSantis announced an $8.6 million dollar investment to expand the state's charging stations by 50 percent along the most traveled corridors.[6] Table 2 illustrates the TYSP Utilities' projected counts of public plug-in electric vehicle (PEV) charging stations throughout the ten-year planning period, resulting in approximately 7,047 charging stations by 2029. The estimated PEV charging station counts listed in Table 2 include both normal and "quick-charge" public charging stations.[7]

[5] CS/SB 7018, 2020 Senate, 2020 Reg. Sess. (FL. 2020).

[6] "Governor Ron DeSantis Announces Next Steps to Strengthen Florida's Electric Vehicle Infrastructure," July 10, 2020, www.flgov.com/2020/07/10/governor-ron-desantis-announces-next-steps-to-strengthen-floridas-electric-vehicle-infrastructure/., accessed on August 10, 2020.

[7] "Quick-charge" PEV charging stations are those that require a service drop greater than 240 volts and/or use three-phase power.

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

YEAR	FPL	TECO	GPC	GRU	JEA	TAL	TOTAL
2020	999	340	53	22	91	34	**1,539**
2021	1,300	386	68	24	105	34	**1,918**
2022	1,629	433	86	26	120	34	**2,327**
2023	1,981	479	104	28	135	34	**2,760**
2024	2,375	525	125	30	150	34	**3,239**
2025	2,827	571	149	33	166	38	**3,784**
2026	3,365	617	177	36	182	38	**4,415**
2027	4,005	663	210	39	199	38	**5,154**
2028	4,766	710	251	42	217	40	**6,026**
2029	5,673	756	298	45	235	40	**7,047**

Source: TYSP Utilities' Data Responses
* Quick-charge PEV station counts included in total Number of Public PEV Charging Stations.
* DEF did not provide estimates of the number of public PEV charging stations in their service territory.

Table 3 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2029. Across the TYSP utilities, anticipated growth would result in an annual energy consumption of 2,254.4 GWh by 2029. Despite this relatively rapid growth rate, current estimates represent an impact of less than 1 percent on net energy for load by 2029.

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

YEAR	FPL	DEF	TECO	GPC	GRU	JEA	TOTAL
2020	41.5	5.7	23.1	1.3	1.3	7.3	**80.2**
2021	88.1	23.1	27.6	2.9	1.5	9.1	**152.1**
2022	147.7	49.6	32.9	4.8	1.7	10.6	**247.2**
2023	226.0	83.4	39.2	7.1	2.0	12.1	**369.8**
2024	349.5	125.2	46.4	9.9	2.4	13.6	**547.0**
2025	504.1	175.6	54.6	13.3	2.7	15.2	**765.6**
2026	696.3	234.8	63.5	17.5	3.1	16.9	**1,032.1**
2027	934.4	300.5	72.9	22.6	3.6	18.7	**1,352.6**
2028	1,243.4	373.8	82.8	28.7	4.2	20.5	**1,753.5**
2029	1,644.0	453.5	93.4	36.2	4.9	22.4	**2,254.4**

Source: TYSP Utilities' Data Responses
*TAL 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, as part of rate case settlement agreements, have initiated electric vehicle pilot programs. 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

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. Demand-side management (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 and one natural gas utility, 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), two municipal electric utilities, JEA and OUC, and an investor-owned natural gas utility, Peoples Gas System. The electric FEECA utilities represented approximately 87 percent of 2019 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 TYSP 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, 2019, demand response available for reduction of peak load is 2,985 MW for summer peak and 2,794 MW for winter peak. Demand response is anticipated to increase to approximately 3,373 MW for summer peak and 3,247 MW for winter peak by 2029.

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, 2019, energy efficiency is responsible for peak load reductions of 4,508 MW for summer peak and 4,024 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,977 MW for summer peak and 4,423 MW for winter peak by 2029.

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.

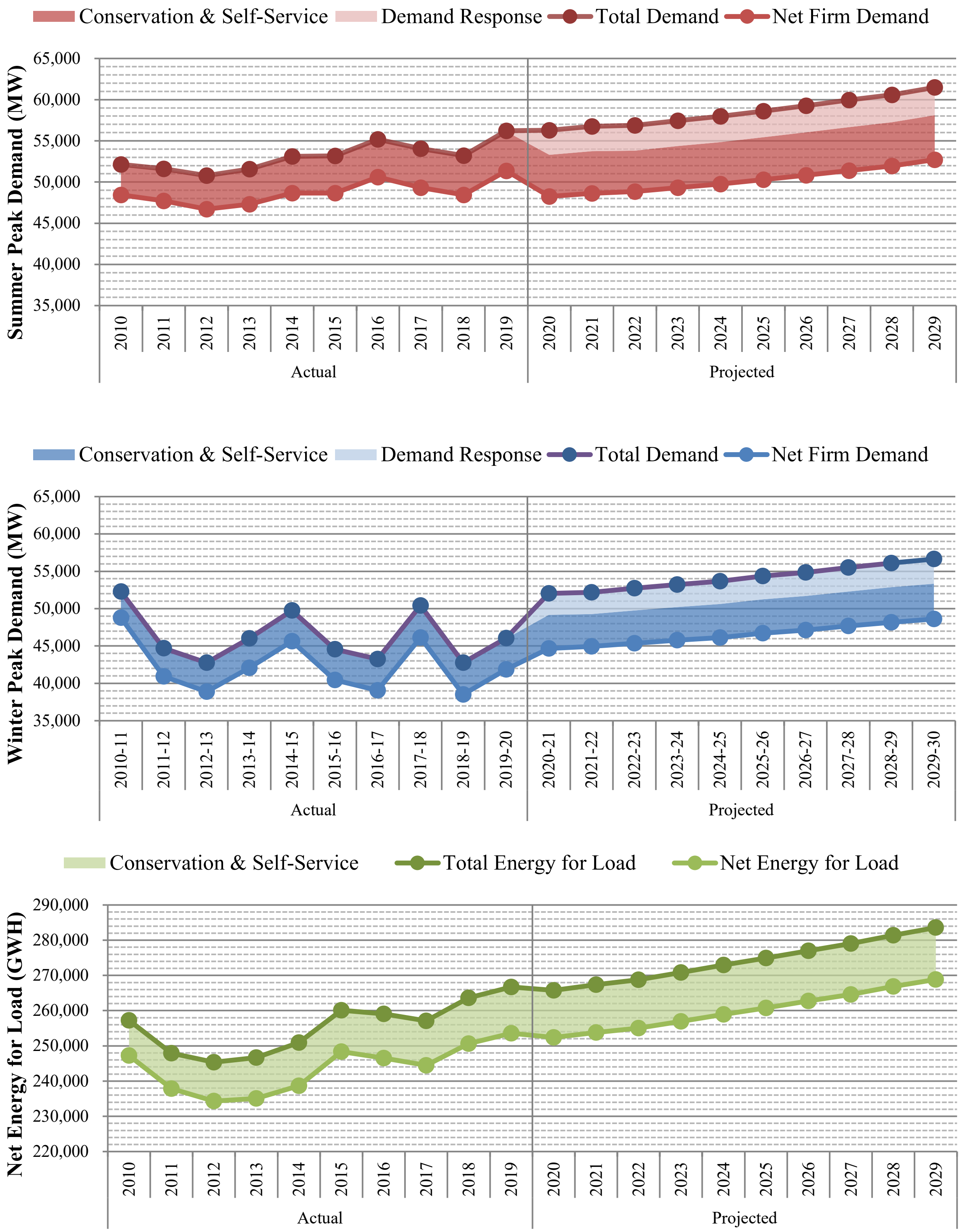
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served 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. Only one of the past ten years have had higher winter net firm demand than summer, and all ten of the forecast years are anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities do not anticipate exceeding the 2010-11 winter net firm demand during the planning period.

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



Source: FRCC 2020 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 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 projecting 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 2019 retail energy sales were compared to the forecasts made in 2014, 2015, and 2016. 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 2020 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2015 through 2019 to forecasts made between 2010 and 2016. As discussed previously, in the period before the 2007-08 economic recession, electric utilities experienced a higher annual growth rate for retail energy sales than the post-crisis 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 TYSPs. The forecasting error rates (five-year rolling average and/or absolute average) derived from 2018 to 2020 TYSPs 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	2011 - 2007	2008 - 2002	11.99%	11.99%
2013	2012 - 2008	2009 - 2003	15.22%	15.22%
2014	2013 - 2009	2010 - 2004	16.27%	16.27%
2015	2014 - 2010	2011 - 2005	14.99%	14.99%
2016	2015 - 2011	2012 - 2006	12.55%	12.55%
2017	2016 - 2012	2013 - 2007	9.19%	9.19%
2018	2017 - 2013	2014 - 2008	6.07%	6.07%
2019	2018 - 2014	2015 - 2009	3.58%	3.58%
2020	2019 - 2015	2016 - 2010	2.26%	2.42%

Source: 2002-2020 Ten-Year Site Plans

To verify whether more recent forecasts lowered the 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 in Table 5.

As displayed in Table 5, the utilities' retail energy sales forecasts show a consistent positive error rate before 2010. The error rates reach a peak during the period 2009 through 2013. Starting in 2014, the error rates have declined considerably; and the error rates calculated based on recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2009-2013 sales forecasts. Additionally, the last five years' one-year ahead forecasts, the last two years' two-year ahead forecasts, and the last year's three-year ahead forecast all bear negative error rates (under-forecasts). The current TYSP also shows a very small error rate with respect to both average and absolute average 3-5 year error percentages.

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		
2008	7.02%	8.40%	8.56%	9.97%	9.24%	8.34%	8.98%	8.98%
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%

Source: 2003-2020 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years may be more reflective of the error rates shown for 2015 through 2019 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 U.S. economy to an extent possibly worse than the 2007-08 recession, and there remains uncertainty as to when the economic impacts of the pandemic will end. As a result, the actual retail energy sales beginning in 2020 could be lower than what Florida utilities predicated in 2019 and prior years. Consequently, the average forecasted energy sales error rates in the next few years may be increased relative to the lower levels recently recorded. It is important to recognize that the dynamic nature of the economy and the weather continue to 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 4,254 MW of firm and non-firm generation capacity, which represents 6.6 percent of Florida's overall generation capacity of 64,071 MW in 2019. 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	2,658	62.5%
Municipal Solid Waste	514	12.1%
Biomass	431	10.1%
Wind	282	6.6%
Waste Heat	276	6.5%
Hydroelectric	51	1.2%
Landfill Gas	42	1.0%
Renewable Total	4,254	100.00%

Source: FRCC 2020 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the total 4,254 MW of renewable generation, approximately 1,558 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 1,012 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 40 percent of Florida's existing renewable generation capacity comes from non-utility generators, of which municipal solid waste, biomass, and wind 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 TYSP. 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 2019, approximately 514 MW of renewable capacity from over 59,000 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 32 installations and 7.2 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	2012	2013	2014	2015	2016	2017	2018	2019
Number of Installations	5,302	6,697	8,581	11,626	15,994	24,166	37,862	59,508
Installed Capacity (MW)	42.2	63.0	79.8	107.5	141	205	317	514

Source: Annual Utility Reports

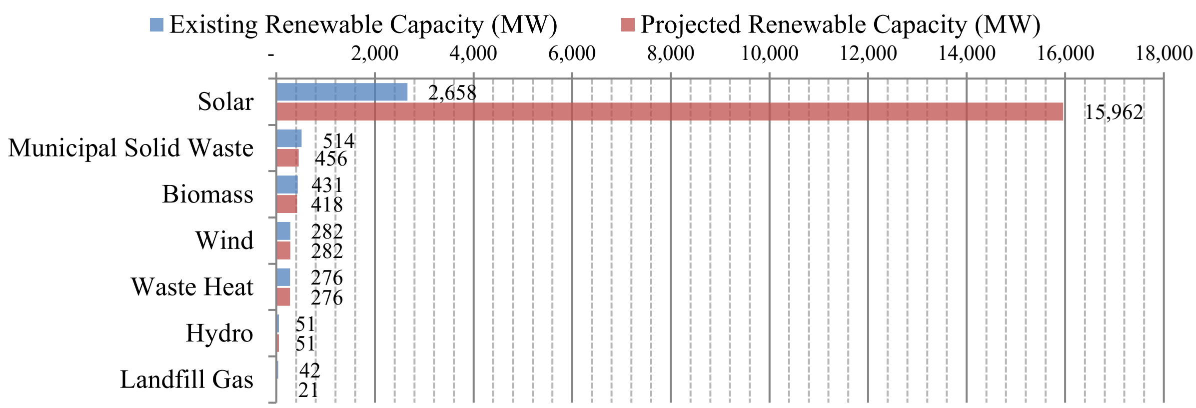
Utility-Owned Renewable Generation

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 1,890 MW of existing utility-owned solar capacity, approximately 996 MW, or about 53 percent, is considered firm.

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 13,212 MW over the 10-year planning period, a significant increase from last year's estimated 10,704 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 2020 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the 13,212 MW projected net increase in renewable capacity, firm resources contribute 4,744 MW, or about 36 percent, of the total. Solar generation alone contributes an incremental 4,835 MW of firm generation capability.[8] 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 total of 13,303 MW to be installed. This consists of 11,077 MW of utility-owned solar and 2,228 MW of contracted solar. In 2016, the Commission approved a settlement agreement entered into by FPL that included a provision for a Solar Base Rate Adjustment (SoBRA) mechanism.[9] The SoBRA mechanism details a process by which FPL may seek approval from the Commission to recover costs for solar projects brought into service that meet certain project cost and operational criteria. In 2017, the Commission approved settlement agreements entered into by DEF and TECO that also included provisions for similar SoBRA mechanisms.[10,11] As a result of their settlement agreements, FPL, DEF, and TECO are projecting solar capacity additions through SoBRA mechanisms totaling approximately 1,200 MW, 700 MW, and 600 MW, respectively. The Commission has approved approximately 1,200 MW of FPL's SoBRA capacity, 344 MW of DEF's SoBRA capacity, and 550 MW of TECO's SoBRA capacity. FPL, DEF, and TECO are also projecting solar capacity additions throughout the remainder of the planning period outside of their respective SoBRA mechanisms. Table 8 provides an overview of the additional solar capacity generation planned within the next 10 years.

[8] Incremental solar firm capacity is greater than the total incremental firm capacity due to losses in firm capacity in other renewable categories.
[9] 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.*
[10] 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.*
[11] Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

Table 8: TYSP Utilities - Planned Solar Installations

Year	Utility	Type	Capacity (MW)
2020	FPL	Utility Owned	1,267
	DEF	Combined	374
	TECO	Utility Owned	149
	FMPA	Purchased	75
	OUC	Purchased	108
		2020 Subtotal	**1,973**
2021	FPL	Utility Owned	745
	DEF	Combined	206
	TECO	Utility Owned	210
	JEA	Purchased	250
		2021 Subtotal	**1,410**
2022	FPL	Utility Owned	447
	DEF	Combined	300
	TECO	Utility Owned	224
	OUC	Purchased	74
		2022 Subtotal	**1,044**
2023	FPL	Utility Owned	447
	DEF	Combined	300
	TECO	Utility Owned	224
	FMPA	Purchased	224
	GRU	Purchased	50
	OUC	Purchased	74
	SEC	Purchased	298
		2023 Subtotal	**1,617**
2024	FPL	Utility Owned	447
	DEF	Combined	225
		2024 Subtotal	**672**
2025	FPL	Utility Owned	745
	DEF	Combined	225
		2025 Subtotal	**970**
2026	FPL	Utility Owned	1,192
	DEF	Combined	150
		2026 Subtotal	**1,342**
2027	FPL	Utility Owned	1,192
	DEF	Combined	150
		2027 Subtotal	**1,342**
2028	FPL	Utility Owned	1,192
	DEF	Combined	150
		2028 Subtotal	**1,342**
2029	FPL	Utility Owned	1,192
	DEF	Combined	150
		2029 Subtotal	**1,342**
TBD	DEF	Purchased	250
		TBD Subtotal	**250**
		Total Installations	**13,303**

Source: FRCC 2020 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.

The Commission has approved rate case settlement agreements from several utilities that include battery storage pilot programs. FPL is deploying 50 MW of batteries through 2020 as part of its 2016 settlement.[12] DEF also plans to implement 50 MW of batteries through 2022 as part of its 2017 settlement.[13]

FPL has proposed adding 469 MW of battery storage in late 2021 or early 2022. Approximately 409 MW of this capacity will be located in Manatee County and will partially offset the loss of generation from the retirement of Manatee Units 1 & 2. FPL expects that the battery will, in part, be charged by solar energy. The remaining 60 MW will be divided into two 30 MW storage facilities to be installed at two different locations. In addition, FPL plans five pilot projects totaling 28 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. FPL is projecting over 700 MW of additional battery storage facilities to be added by 2029.

DEF has announced three Li-ion battery storage projects, totaling 22 MW. These projects consist of an 11 MW facility in Gilchrist County, a 5.5 MW facility in Gulf County, and a 5.5 MW in Hamilton County. DEF intends to complete the three projects by the end of 2020. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages.

TECO installed a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County that was put into service in 2019. This facility is interconnected with the solar array and is expected to add 5.6 MW of firm capacity. Additionally, the project is expected to benefit contingency reserves. TECO is projecting over 200 MW of battery storage over the planning horizon.

If current market trends in battery technology continue, Florida can expect battery storage capacity to increase over the planning period. Staff will continue to review and observe developments in this field.

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[12] 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.*

[13] 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

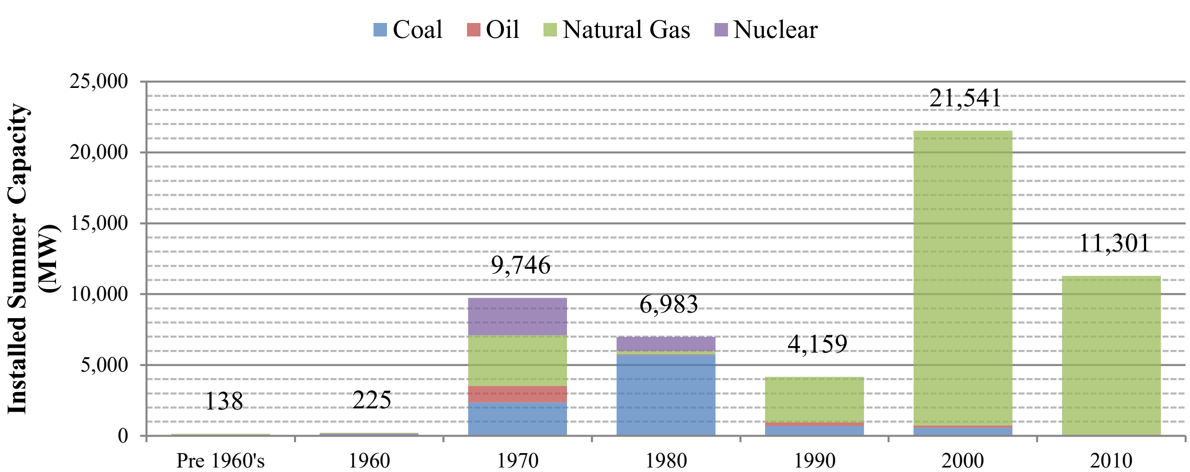
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. 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 21 years. While the original commercial in-service date may be in excess of 60 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 12 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 12: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2020 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, six[14] EPA rules were anticipated to affect electric generation in Florida:

- 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 Affordable Clean Energy (ACE) rule. ACE establishes carbon emission guidelines such that each state must perform site-specific reviews to determine the applicable standard of performance using 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.

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

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[14] The Cross-State Air Pollution Rule (CSAPR) requires certain states to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The Rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within the upwind states. Originally, the Rule included Florida, however, the final Rule, issued September 7, 2016, removes North Carolina, South Carolina, and Florida from the program because modeling for the final Rule indicates that these states do not contribute significantly to ozone air quality problems in downwind states.

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, 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 9 lists the 4,778 MW of existing generation that is scheduled to be retired during the planning period. Within the next 10 years, 12 natural gas units totaling 2,299 MW, 6 coal units totaling 1,920 MW, and 13 oil units totaling 559 MW are scheduled to retire. Notably, TECO plans to retire its natural gas-fired Big Bend Unit 2 in 2021 and convert its natural gas-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023 as part of its Big Bend Power Station modernization.

Table 9: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Summer
2020	DEF	Avon Park 1	NG – CT	24
	DEF	Avon Park 2	DFO – CT	24
	LAK	C.D. McIntosh 2	NG – ST	106
			2020 Subtotal	**154**
2021	FPL/GPC	Manatee 1 & 2	NG – ST	1,618
	FPL/GPC	Scherer 4	BIT – ST	634
	TECO	Big Bend 2	NG – ST	385
			2021 Subtotal	**2,637**
2022	GRU	Deerhaven FS01	NG – ST	75
	SEC	Seminole Generating Station 1 or 2*	BIT – ST	634
			2022 Subtotal	**709**
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	172
	FPL/GPC	Pea Ridge 1 - 3	NG – CT	12
			2025 Subtotal	**184**
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	Univ. of Fl P1	NG – CT	44
	DEF	Bartow P1 & P3	DFO – CT	82
	FPL/GPC	Lansing Smith A	DFO – CT	32
			2027 Subtotal	**407**
			Total Retirements	**4,778**

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

Source: 2020 Ten-Year Site Plans

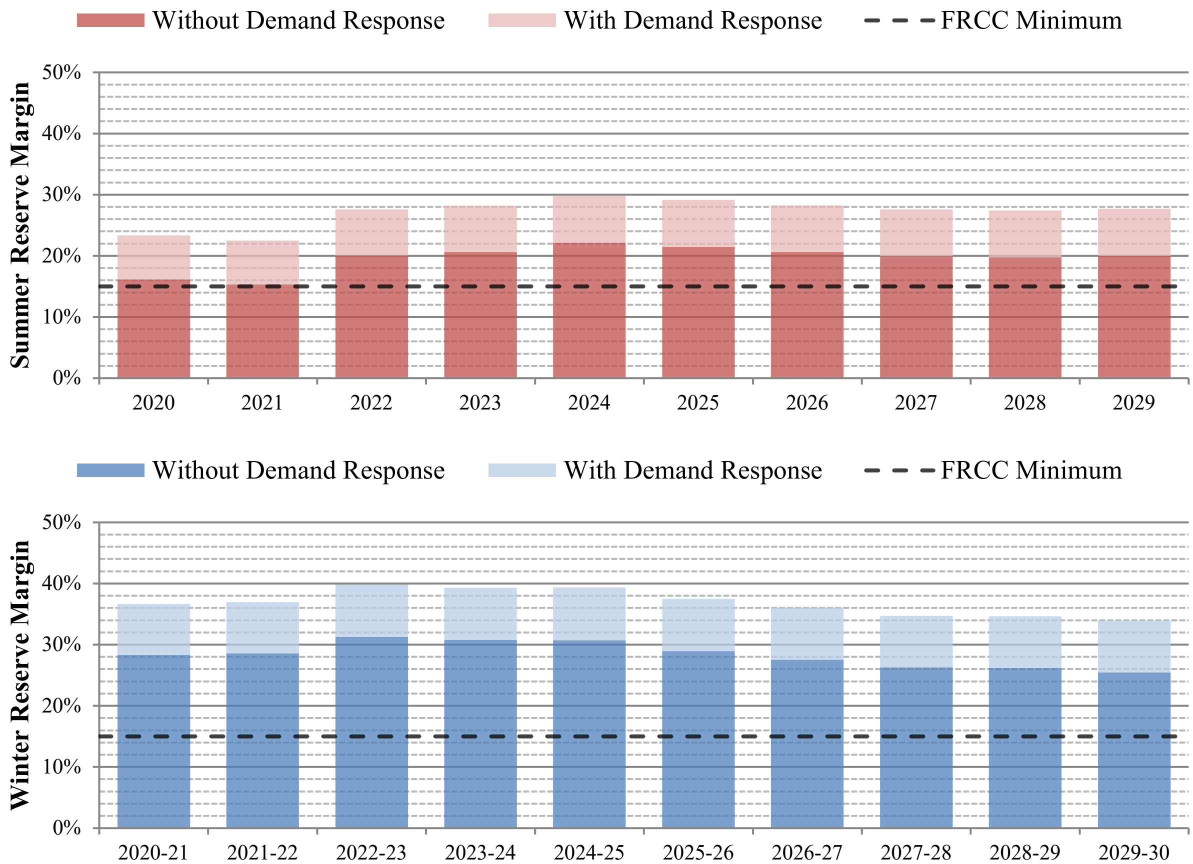
Reliability Requirements

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 13 is a projection of the statewide seasonal reserve margin including all proposed power plants.

Figure 13: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2020 Regional 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 13, 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.

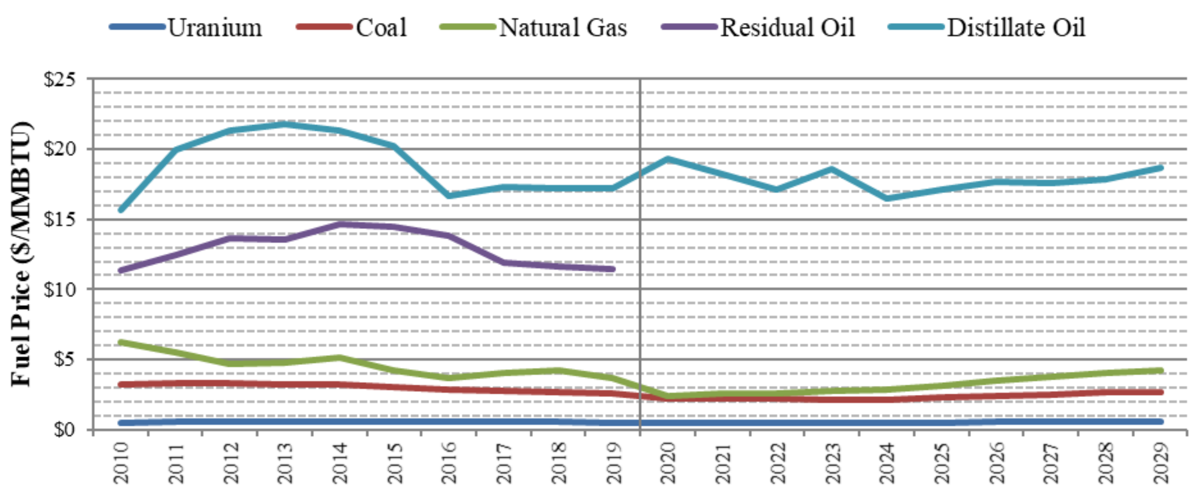
Demand response participants receive discounted rates or credits regardless of activation, with these costs recovered from all ratepayers. Because of the voluntary nature of demand response, a concern exists that a heavy reliance upon this resource would make participants eschew the discounted rates 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. Figure 14 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

Distillate oil remains the most expensive fuel, which explains why it is used for backup and peaking purposes only. Also of note is a phasing out of residual oil, with no forecast for purchasing residual oil after 2021. Figure 14 has excluded projected oil prices to reflect this trend.

Figure 14: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities



Source: Utilities Responses to FPSC Staff's Data Requests

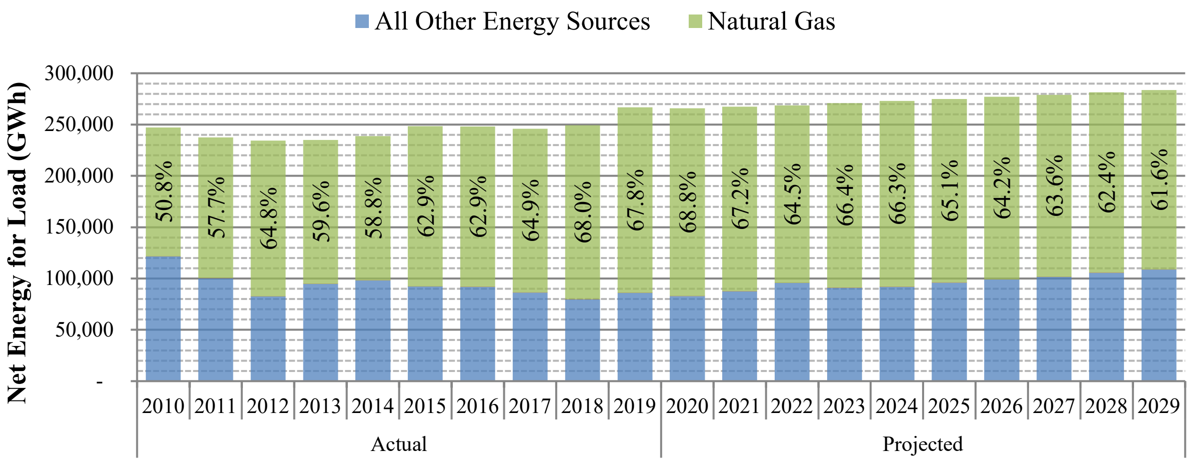
From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This led to concerns regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Concerns regarding potential environmental regulations, and other projected costs, lead to plans for new coal-fired generation not materializing. Traditionally, coal was the lowest cost fuel, other than uranium, and was dispatched before most natural gas-fired units. While natural gas-fired units have the advantage of a lower heat rate, and therefore require fewer units of thermal energy per unit of electrical energy produced, the fuel price differential allowed coal to remain dominant until 2008.

As shown in Figure 14, the price of natural gas declined precipitously after the financial crisis of 2008, and is forecasted to remain well below pre-2009 levels. Broad application of hydraulic fracturing and resource recovery techniques played a major role in lowering the price of natural gas. The smaller price differential between coal and natural gas, and the higher efficiency of natural gas combined cycle units has shifted the order of generation dispatch, with natural gas units displacing many of Florida utilities' coal units.

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida and since 2010 has generated more net energy for load than all other fuels combined. As Figure 15 illustrates, natural gas was the source of approximately 68 percent of electric energy consumed in Florida in 2019. 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 15: State of Florida - Natural Gas Generation

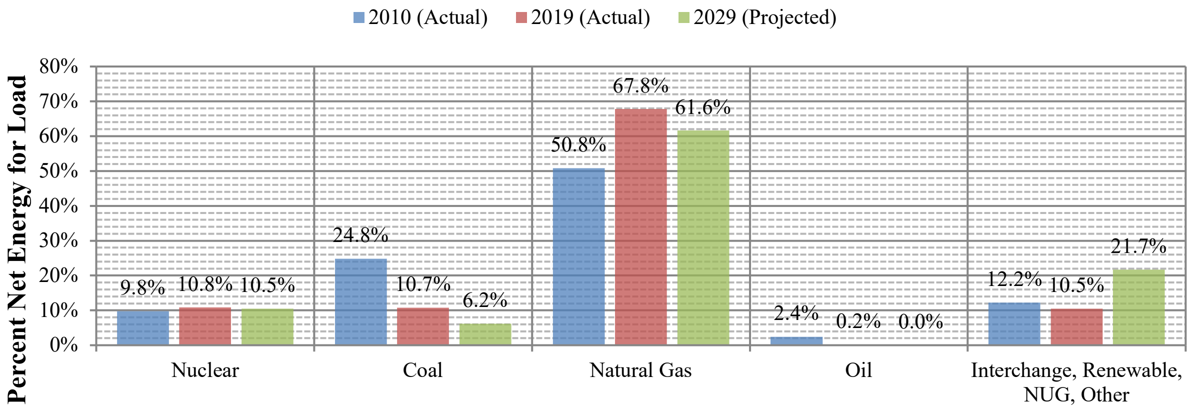


Source: FRCC 2011-2020 Regional Load and Resource Plan

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 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 16 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2010 and 2019, and forecast year 2029. 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 was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. 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 16: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2011-2020 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.[15] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Florida's percentage of natural gas electric generation is the highest in the country, with 86 percent of all natural gas consumed in the state for electricity. 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

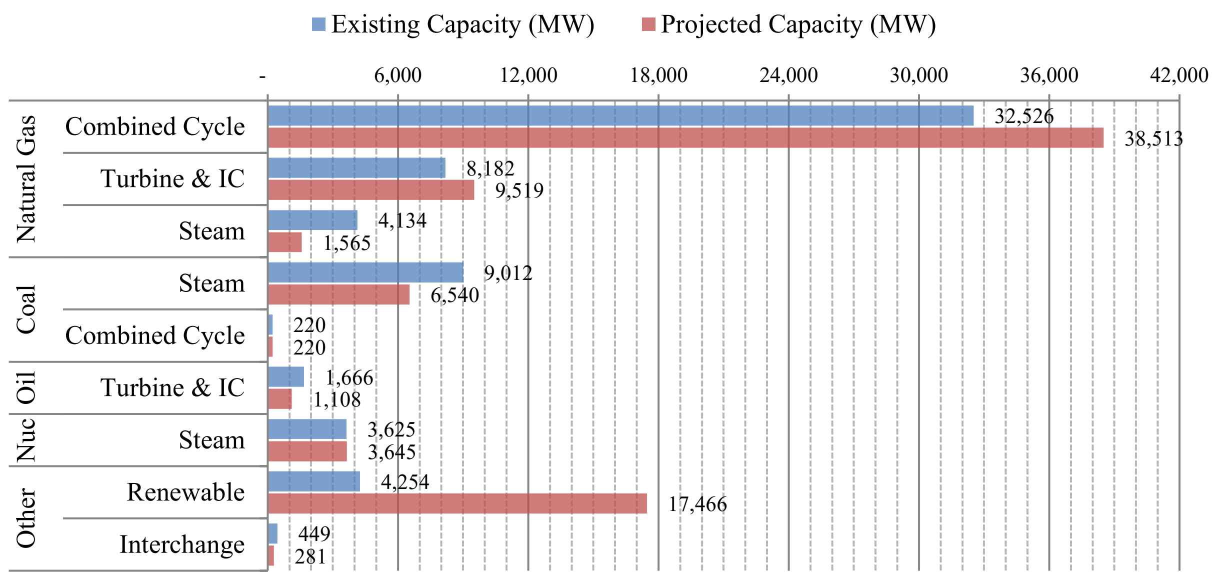
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant,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

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

Figure 17 illustrates the present and future aggregate capacity mix. The capacity values in Figure 17 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2020 Ten-Year Site Plans and the FRCC's 2020 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 17: State of Florida - Current and Projected Installed Capacity by Fuel



Source: FRCC 2020 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 TYSP. 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 10 summarizes the approximately 4,841 MW of additional capacity from new natural gas-fired generating units proposed by the 2020 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 10: 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	1,108	Docket No. 20170266-EI
			Subtotal	**2,271**
New Units Not Requiring PPSA Approval				
2020	LAK	C.D. McIntosh 2	115	
	TAL	Hopkins 5	18	
2021	TECO	Big Bend 5 & 6	660	Convert to CC in 2023
	TECO	Reciprocating Engine 1-5	93	
	FPL	Crist Unit 8	938	
2025	TECO	Reciprocating Engine 6	19	
2027	TECO	Reciprocating Engine 7-10	74	
	SEC	Unnamed Reciprocating Unit 1	92	
2028	DEF	Undesignated CT P1	226	
	TAL	Unsited 1	18	
	SEC	Unnamed Reciprocating Unit 2	92	
2029	DEF	Undesignated CT P2	226	
			Subtotal	**2,570**
			Total Planned Natural Gas Capacity	**4,841**

Source: 2020 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 11 lists all proposed transmission lines in the 2020 Ten-Year Site Plans and the FRCC 2020 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 11: 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-Midway (Note 1)	150	500	5/28/1988	4/20/1990	2030
TECO	Thonotosassa to Wheeler	8	230	6/21/2007	8/7/2008	TBA
TECO	Wheeler to Willow Oak	17	230	6/22/2007	8/7/2008	TBA
TECO	Lake Agnes to Gifford	10.5	230	9/26/2007	2/5/2009	TBA

Source: 2020 Ten-Year Site Plans & FRCC 2020 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 TYSP 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 2020 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

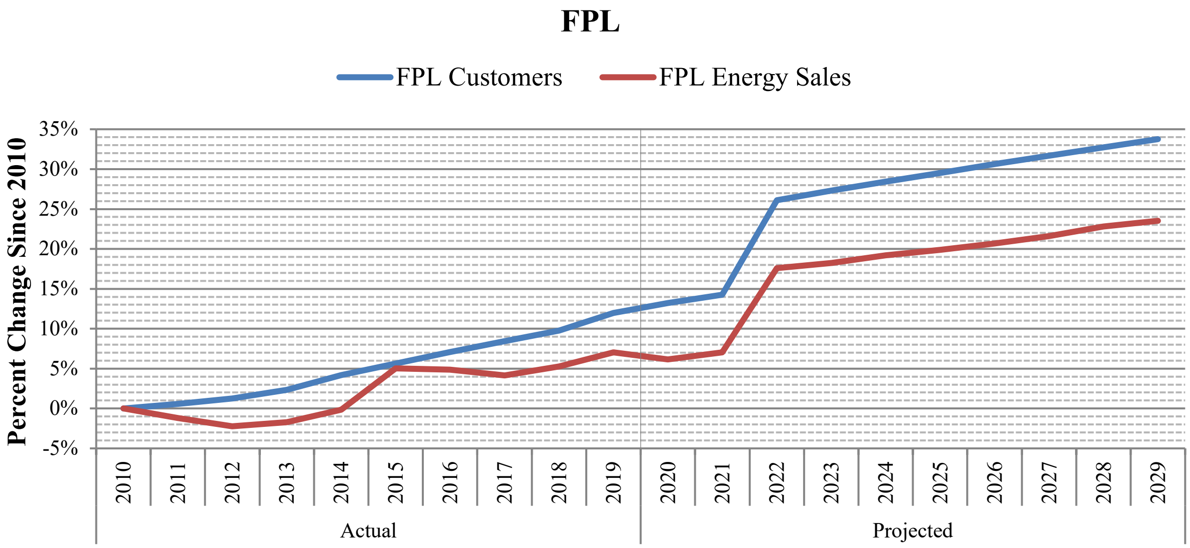
In 2019, FPL had approximately 5,061,525 customers and annual retail energy sales of 111,929 GWh, or approximately 48.1 percent of Florida's annual retail energy sales. As a result of FPL's acquisition of Vero Beach during the fourth quarter of 2018, FPL's total customers grew 2.0 percent in 2019, compared to the growth of 1.2 percent in 2018. The utility's retail energy sales have shown a slight increasing growth trend driven by growth in the number of customers, which somewhat offsets the continuous downward trend in the average consumption per customer attributed to the energy efficiency improvements. Figure 18 illustrates FPL's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the past 10 years, FPL's customer base has increased by 11.97 percent, while retail sales have grown by 7.05 percent. The utility's retail energy sales are anticipated to slightly exceed its historic 2019 peak in 2021 before the integration of FPL's and GPC's electric systems.

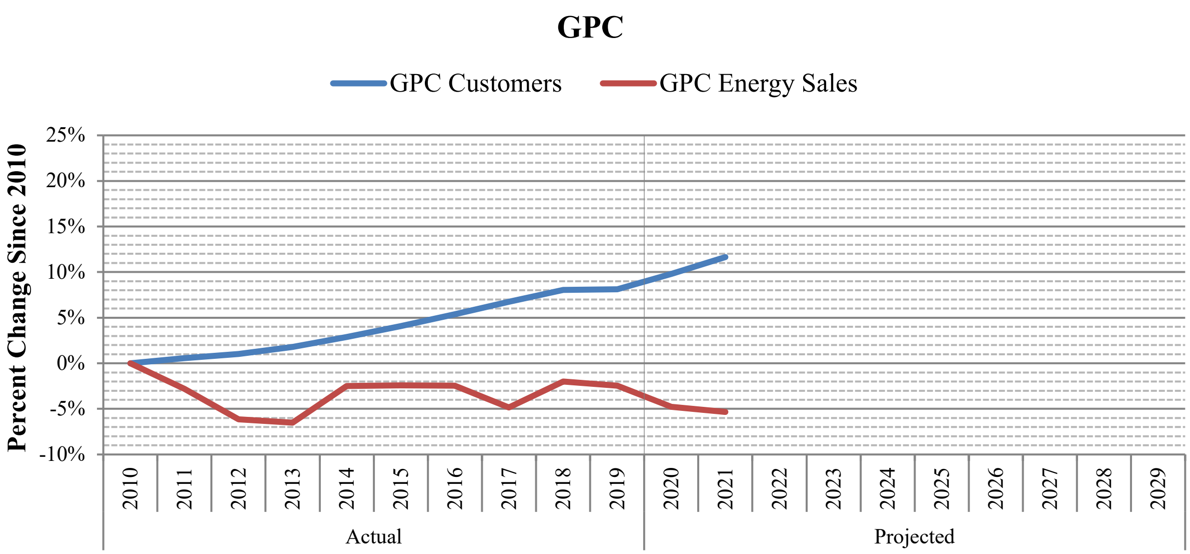
In 2019, GPC had approximately 464,884 customers and annual retail energy sales of 11,070 GWh, or approximately 4.8 percent of Florida's annual retail energy sales. Figure 18 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales from 2010 to 2021, at which 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 8.10 percent, while retail sales have decreased by 2.47 percent. GPC's retail energy sales are anticipated to further decrease for the period 2020 -21 before its system is integrated with FPL's electric system.

In FPL's and GPC's 2020 TYSPs, the utilities' combined growth rate of their annual average total customers is reduced to some extent compared to what was projected in the 2019 TYSPs. This reduction is primarily a result of the downward revisions to the forecasts of population and housing starts by the consulting company HIS Markit. The other driving factor for the reduction in annual average customer growth rate is the impact of Hurricane Michael in October 2018, which caused permanent customer loss for GPC. The forecasts presented in the 2019 TYSPs did not reflect such impact due to the timing of the forecast development.

For the instant TYSPs, all the utilities presented forecasts of customer growth and energy sales developed before the onset of the COVID-19 pandemic which has significantly damaged the global and US economies. As a result, the utilities' energy sales are also being affected. In August 2020, FPL and GPC reported that, on a weather-adjusted basis, their energy sales to residential customers have increased beginning in late March 2020, while sales to the commercial and industrial customers decreased, resulting in a slight decrease in Total Sales to Ultimate Customers. The TYSP Utilities have not completed new sales forecasts that reflect the impact from the COVID-19 pandemic at this time.

Figure 18: FPL & GPC Growth





Source: 2020 Ten-Year Site Plan

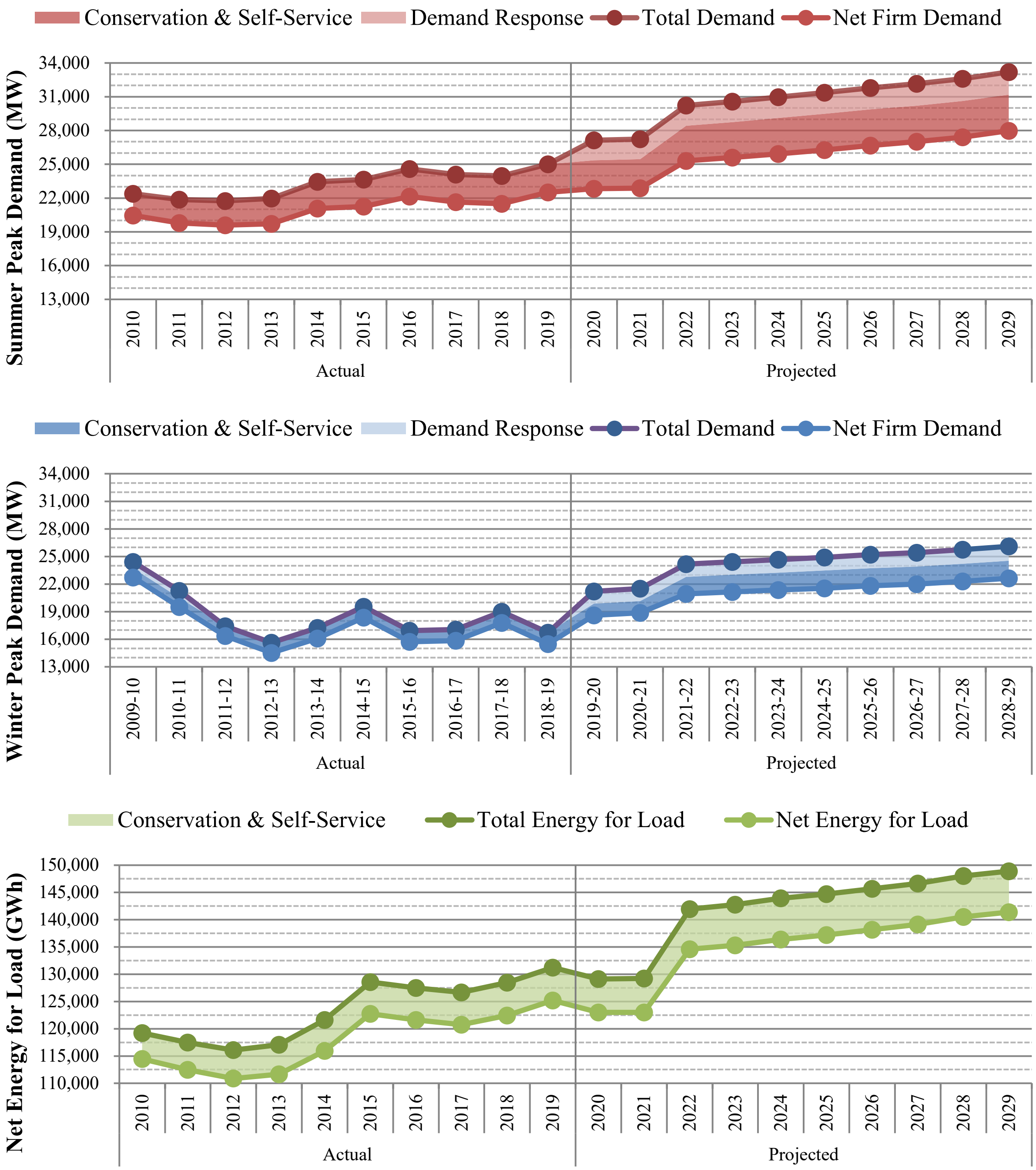
As mentioned earlier, on January 1, 2019, GPC became a subsidiary of NextEra, FPL's parent company. FPL and GPC plan to integrate the two systems into a single electric system, effective January 1, 2022. For the instant report, the demand and energy forecasts for FPL and GPC are presented separately for the years 2020 and 2021. For years 2022 through 2029, the demand and energy forecasts for FPL/GPC are presented as a single integrated utility (FPL), as depicted in Figure 19.

The three graphs in Figure 19 show FPL's seasonal peak demand and net energy for load, for the historic years 2010 through 2019 and forecast years 2020 through 2029. 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 winters of 2009-10 and 2010-11.

The three graphs in Figure 20 show GPC's seasonal peak demand and net energy for load, for the historic years 2010 through 2019 and forecast years 2020 through 2021. GPC's demand and energy forecasts sharply decline to zero after 2021 due to the utility's planned integration with FPL's system.

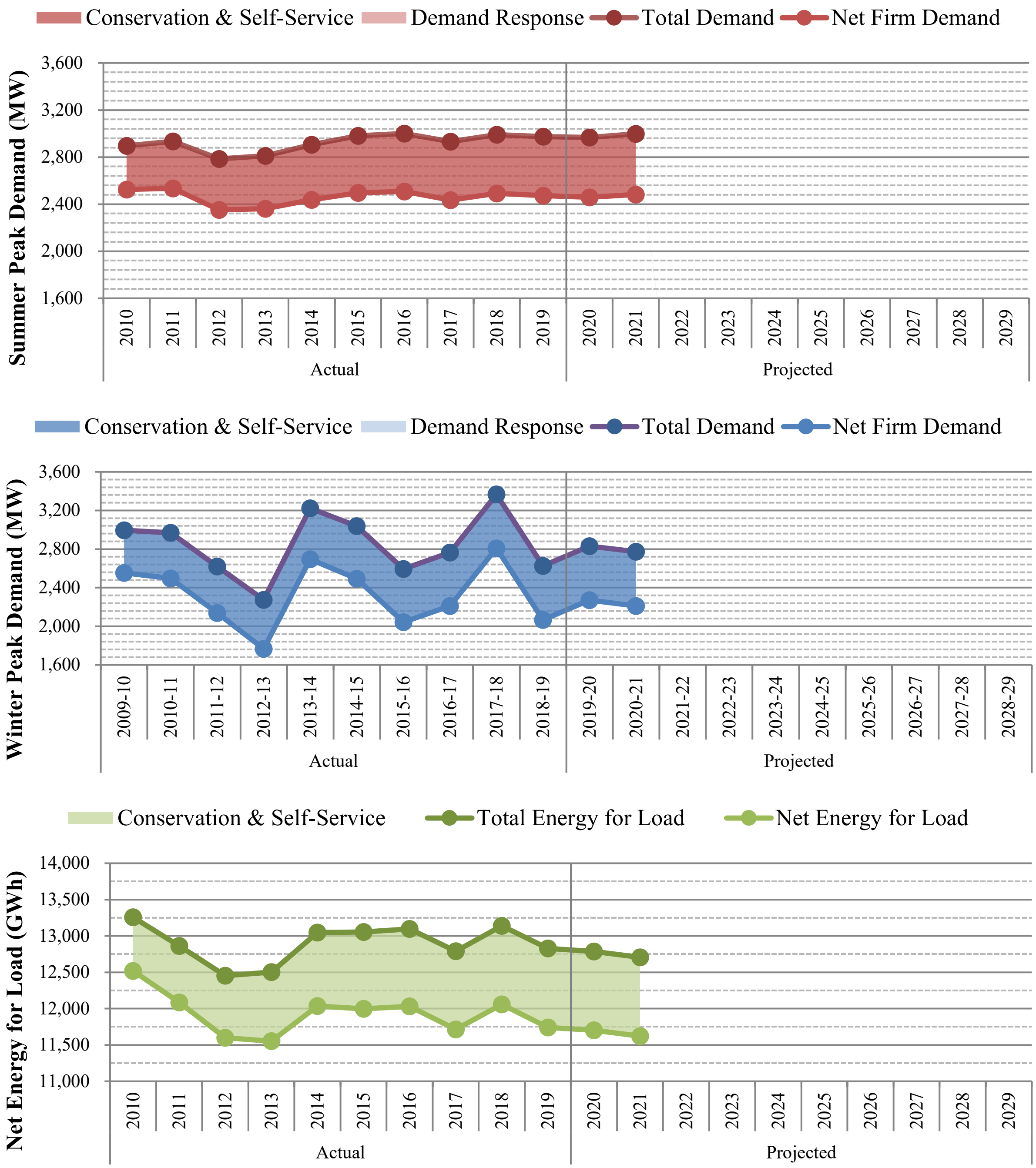
As investor-owned utilities, FPL and GPC are subject to FEECA and currently offer energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020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

Figure 19: FPL Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Figure 20: GPC Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 12 shows FPL's and GPC's actual net energy for load by fuel type for 2019, and the projected fuel mix for the combined companies for 2029. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 96 percent of net energy for load in 2019. GPC was an energy exporter in 2019, producing approximately 30 percent more energy than it required for native load. While natural gas was the dominant fuel source in 2019, coal was the second most utilized fuel source. FPL projects that renewable energy will provide over 16 percent of its generation by 2029, which is the second highest percentage of renewable energy generation in 2029 of the TYSP Utilities.

Table 12: FPL and GPC Energy Generation by Fuel Type

Fuel Type	Net Energy for Load					
	FPL		GPC		FPL	
	2019		2019		2029	
	GWh	%	GWh	%	GWh	%
Natural Gas	93,373	**74.6%**	8,808	**75.0%**	87,157	**61.9%**
Coal	2,488	**2.0%**	4,125	**35.1%**	232	**0.2%**
Nuclear	27,791	**22.2%**	0	**0.0%**	28,590	**20.3%**
Oil	477	**0.4%**	0	**0.0%**	5	**0.0%**
Renewable	2,396	**1.9%**	1,263	**10.3%**	22,947	**16.2%**
Interchange	0	**0.0%**	-3,556	**-30.3%**	0	**0.0%**
Other	-1,328	**-1.1%**	1.101	**9.4%**	1,789	**1.3%**
Total	**125,167**		**11,741**		**140,720**	

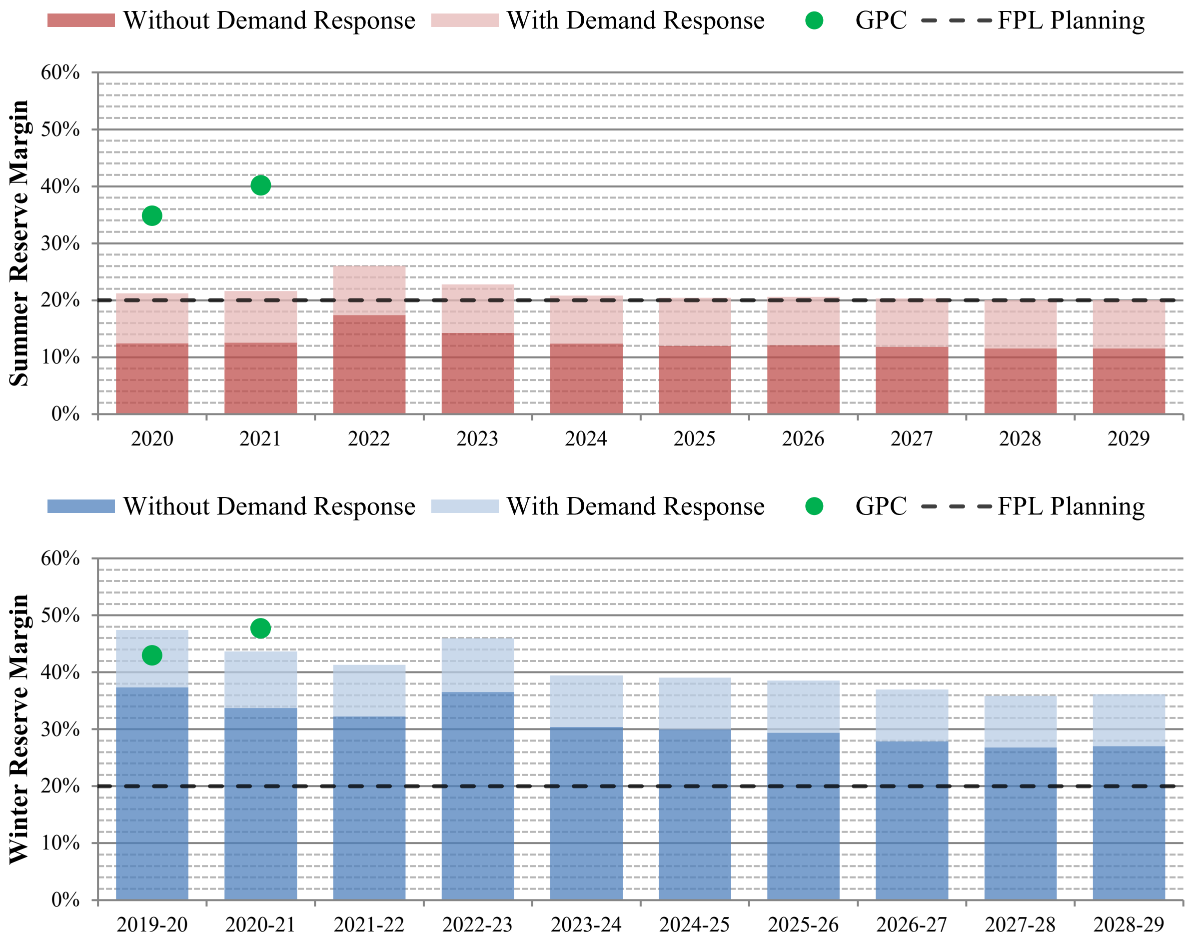
Source: 2020 Ten-Year Site Plan

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 21 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 21: FPL and GPC Reserve Margin Forecast



Source: 2020 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 13 for the FPL region and Table 14 for the GPC region.

A combined total of 1,286 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 (150 MW). FPL also plans to retire 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. Originally set for retirement in 2028, the 2021 retirement of these units is projected to save FPL customers approximately $101 million, net of projected generation and transmission costs needed to offset the loss of 1,618 MW of firm capacity. GPC also plans to retire four smaller oil and gas CT units with a total capacity of 44 MW over the planning period. Some of the retirements for GPC units may vary, as FPL has indicated these retirements borrow from end-of-life depreciation calculations and do not represent results from an operational evaluation of the units.

The projected in-service dates of FPL's planned nuclear units are outside the 10-year planning period. FPL filed a need determination with the Commission on October 20, 2017, for the Dania Beach Clean Energy Center, another natural gas-fired combined cycle unit, which was granted on March 19, 2018. The unit is expected to be in-service by 2022. Before the interconnection with FPL, GPC plans four natural gas-fired CTs, Crist 8, for a total of 938 MW in 2021.

FPL and GPC plan to add a total of 8,879 MW of solar photovoltaic plants over the planning period. FPL's solar additions include: 300 MW of SoBRA approved in the Fuel and Purchased Power Cost Recovery Clause docket, and 1,490 MW from the SolarTogether Program, which was approved by the Commission in March 2020. GPC has sited three solar plants for a total of 225 MW that will go into service before 2022. An additional 5,513 MW of solar is planned for the FPL region and 1,341 MW for the GPC region between 2022 and 2029. All planned solar additions make up approximately 73 percent of FPL's and GPC's planned future units.

FPL and GPC plan to add a total of 1,169 MW of battery storage over the planning period. FPL's 469 MW battery storage project is planned for late 2021, of which 409 MW will be placed in service in Manatee County to offset the retirement of Manatee 1 & 2. FPL plans two more battery projects in the GPC region, 200 MW in 2028 and 500 MW in 2029. 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 13: 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	1,618	N/A	
2021	Scherer 4	BIT- ST	634	N/A	
Total Retirements			**2,252**		
New Units					
2020	Hibiscus	PV	75	41	Docket No. 20190001-EI
2020	Southfork	PV	75	41	
2020	Echo River	PV	75	41	
2020	Okeechobee	PV	75	41	
2020	Northern Preserve	PV	75	41	Docket No. 20190061-EI
2020	Twin Lakes	PV	75	41	
2020	Cattle Ranch	PV	75	41	
2020	Sweetbay	PV	75	41	
2020	Babcock Preserve	PV	75	41	
2020	Blue Heron	PV	75	41	
2020	Egret	PV	75	41	
2020	Lakeside	PV	75	41	
2020	Magnolia Springs	PV	75	41	
2020	Nassau	PV	75	37	
2020	Trailside	PV	75	37	
2020	Union Springs	PV	75	37	
2021	Pelican	PV	75	41	
2021	Rodeo	PV	75	41	
2021	Discovery	PV	75	41	
2021	Willow	PV	75	37	
2021	Orange Blossom	PV	75	37	
2021	Palm Bay	PV	75	37	
2021	Fort Drum	PV	75	37	
2021	Sabal Palm	PV	75	37	
2021	Manatee Energy Storage	BAT	409	N/A	
2021	Sunshine Gateway Energy Storage	BAT	30	N/A	
2021	Echo River Energy Storage	BAT	30	N/A	
2022	Dania Beach Clean Energy Center	NG – CC	1,163	N/A	Docket No. 20170225-EI
2025-29	Unsited Solar	PV	5,513	1,553	
Total New Units			**8,945**	**2,505**	
Net Additions			**6,693**		

Source: 2020 Ten-Year Site Plan

Table 14: GPC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
2024	Daniel 1 & 2	BIT - ST	502	N/A	
2024	Crist 4	BIT – ST	75	N/A	
2025	Pea Ridge 1 – 3	NG – CT	12	N/A	
2026	Crist 5	BIT – ST	75	N/A	
2027	Lansing Smith A	DFO – CT	32	N/A	
Total Retirements			**696**		
New Units					
2020	Blue Indigo	PV	75	41	
2021	Crist 8	NG - CT	938	N/A	
2021	Blue Springs	PV	75	37	
2021	Chautauqua	PV	75	37	
2022-24	Unsited Solar	PV	1,341	642	
2028	Unsited Battery Storage	BAT	200	N/A	
2029	Unsited Battery Storage	BAT	500	N/A	
Total New Units			**3,204**	**642**	
Net Additions			**2,508**		

Source: 2020 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 2020 Ten-Year Site Plan suitable for planning purposes.

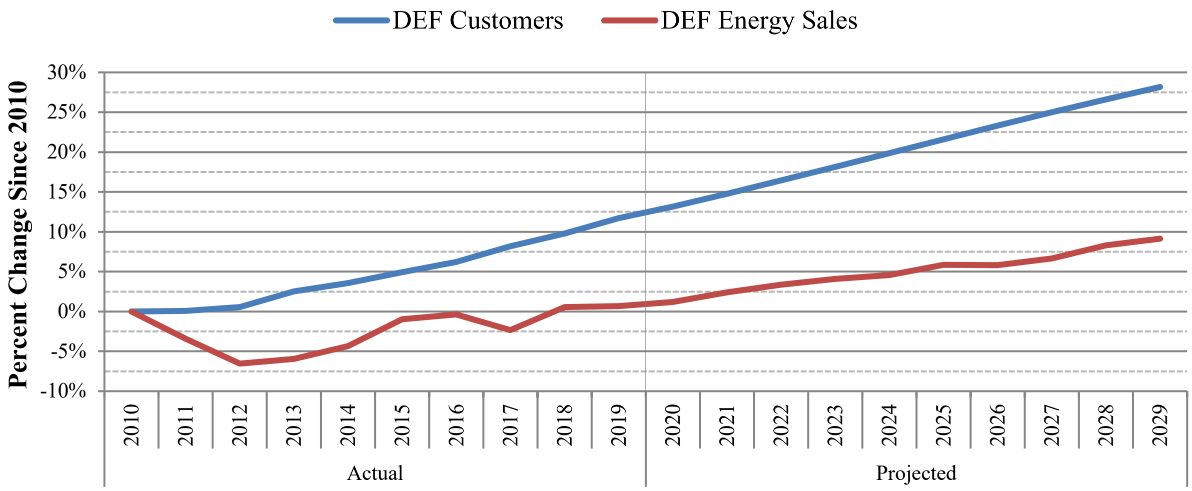
Load & Energy Forecasts

In 2019, DEF had approximately 1,832,885 customers and annual retail energy sales of 39,187 GWh or approximately 16.9 percent of Florida's annual retail energy sales. Figure 22 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales, in terms of percentage growth from 2010. Over the last 10 years, DEF's customer base has increased by 11.70 percent, while retail sales have grown by 0.67 percent.

In the 2020 TYSP, DEF projected a reduction in its customer growth specifically for the period 2022-2024. The utility explained that this is due to nearly 3,000 Hardee County customers being transferred from DEF to Peace River Electric Cooperative (PRECO) as a result of a territorial agreement. The customer forecast in DEF's 2019 TYSP did not reflect this information because the agreement was not yet finalized at the time of completing the 2019 TYSP forecast.

Since the COVID-19 pandemic shutdown in mid-March 2020, DEF's weather-adjusted Total Sales to Ultimate Customers have declined significantly as many businesses and schools were forced to close. The utility revealed that, for the months of April through June 2020, the energy sales showed steep year-over-year declines, which occurred in the commercial, industrial, governmental, and other classes. Contrarily, the residential class experienced gains in energy sales in this same period, which was expected as home occupants remained in the home much more than usual. DEF's actual data for the second quarter of 2020 shows that, in comparison with the original 2020 TYSP forecasts, the sales reductions in commercial and governmental classes are respectively 14.1 percent and 18.4 percent, and the reduction in total retail sales is approximately 6.3 percent. DEF expects that the actual retail sales in 2020 and 2021 would be reduced from what it forecasted in 2020 TYSP due to the impact of the pandemic, although there is still significant uncertainty surrounding the degree of the reduction.

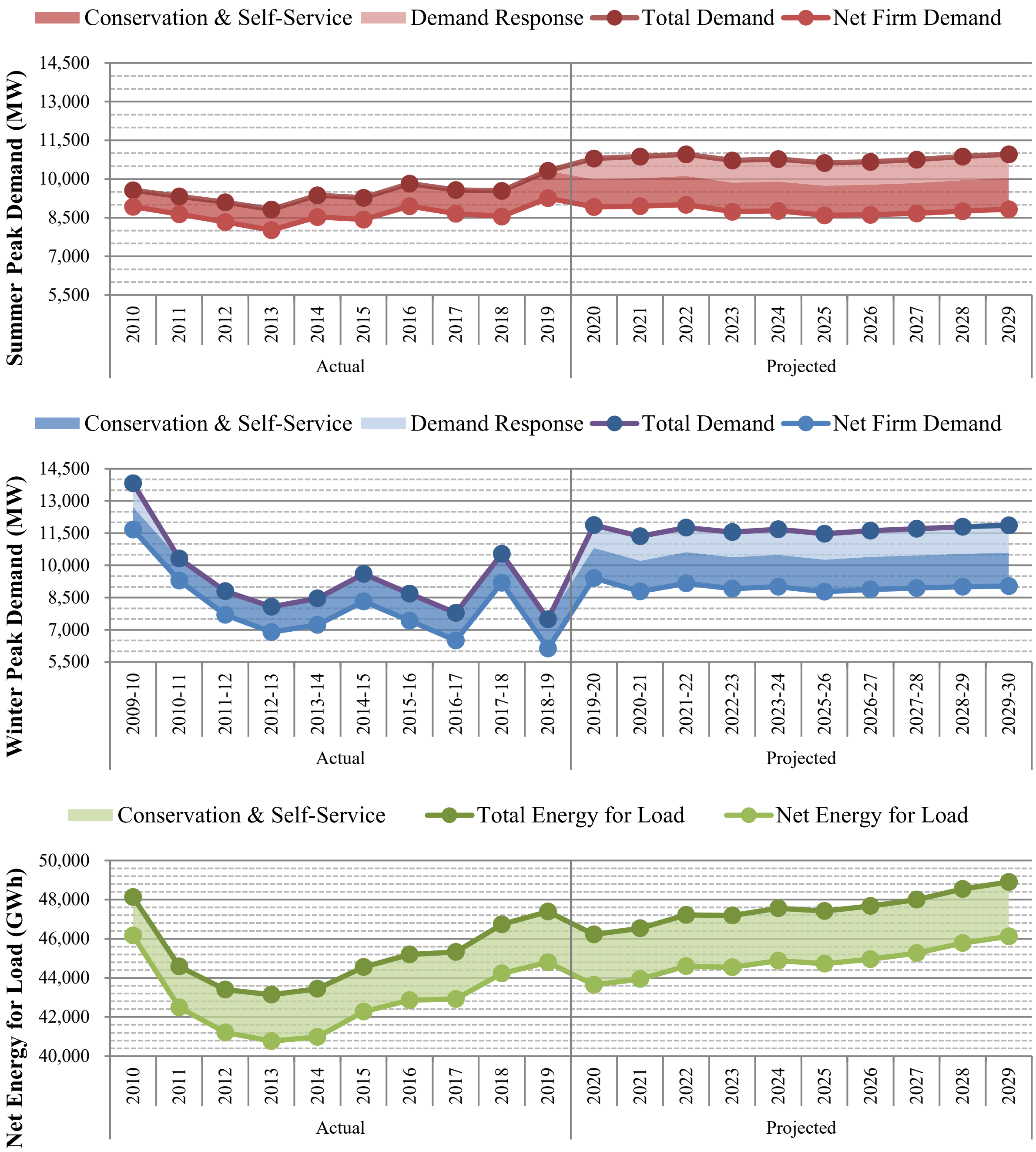
Figure 22: DEF Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 23 show DEF's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 2020 Ten-Year Site Plan reflects these goals.

Figure 23: DEF Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 15 shows DEF's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 88 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 by 2029. DEF projects the third highest percentage of renewable energy generation in 2029 of the TYSP Utilities.

Table 15: DEF Energy Generation by Fuel Type

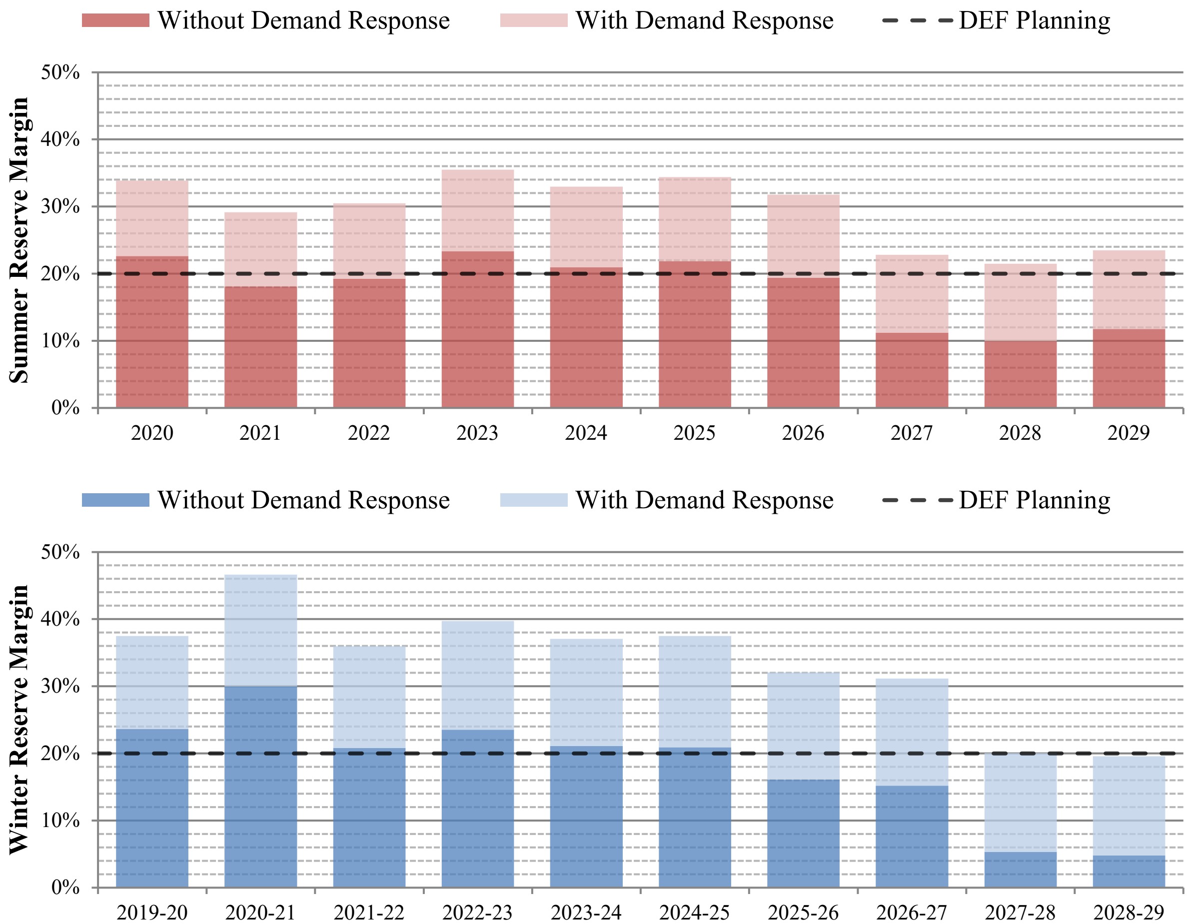
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	35,170	**78.5%**	35,671	**77.3%**
Coal	4,322	**9.6%**	3,540	**7.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	33	**0.1%**	65	**0.1%**
Renewable	907	**2.0%**	6,812	**14.8%**
Interchange	1,277	**2.9%**	34	**0.1%**
NUG & Other	3,093	**6.9%**	2	**0.0%**
Total	**44,801**		**46,124**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 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. It appears, however, that by the winter of 2027-28 DEF's planning will be controlled by its winter peaking needs. Current and planned investments in solar generation contribute to this shift because solar resources provide coincident capacity during the summer peak but not the winter peak. Therefore, DEF's reserve margin, inclusive of demand response, is 19.6 percent in the winter of 2028-29. As DEF approaches this date, the utility will continue to evaluate how to meet its 20 percent reserve margin criterion.

Figure 24: DEF Reserve Margin Forecast



Source: 2020 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 16. 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.

DEF has included 1,254 MW of planned solar additions outside of the 149 MW of SoBRA additions approved by the Commission.[16,17] As a result of forecasts that show the continued reduction in the cost of solar PV technology, DEF has incorporated this energy source as a supply-side resource in both its near-term and long-term generation plans. The solar additions make up approximately 76 percent of DEF's planned total new MW. 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

[16] Order No. PSC-2019-0159-FOF-EI, issued April 30, 2019, in Docket No. 20180149-EI, *In re: Petition for a limited proceeding to approve first solar base rate adjustment, by Duke Energy Florida, LLC.*

[17] Order No. PSC-2019-0292-FOF-EI, issued July 22, 2019, in Docket No. 20190072-EI, *In re: Petition for a limited proceeding to approve second solar base rate adjustment, by Duke Energy Florida, LLC.*

share of new solar energy centers.[18] Therefore, the impact of this petition is not included in Table 16. If approved, the program's impact on other planned solar generation will be addressed in the utility's next Ten-Year Site Plan.

DEF has announced three Li-ion battery storage projects, totaling 22 MW. These projects consist of an 11 MW facility in Gilchrist County, a 5.5 MW facility in Gulf County, and a 5.5 MW in Hamilton County. DEF intends to complete the three projects by the end of 2020. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages.

Table 16: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (Summer)	Notes
			Sum	Sum	
Retiring Units					
2020	Avon Park P1	NG – CT	24	N/A	
2020	Avon Park P2	DFO – CT	24	N/A	
2025	Bayboro P1-4	DFO – CT	171	N/A	
2027	Debary P2-6	DFO – CT	249	N/A	
2027	Bartow P1 & 3	DFO – CT	82	N/A	
2027	University of Florida P1	DFO – CT	44	N/A	
Total Retired MW			**594**	N/A	
New Units					
2020	Debary	PV	75	34	Docket No. 20190072-EI.
2020	Columbia	PV	75	43	Docket No. 20180149-EI.
2021	Twin Rivers	PV	75	43	
2021	Santa Fe	PV	75	43	
2021	Duette	PV	75	43	
2021	Charlie Creek	PV	75	43	
2021	Archer	PV	56	32	
2022	Unknown Solar	PV	150	86	
2023	Unknown Solar	PV	150	86	
2024	Unknown Solar	PV	150	86	
2025	Unknown Solar	PV	150	86	
2026	Unknown Solar	PV	75	43	
2027	Unknown 1	NG – CT	226	N/A	
2027	Unknown Solar	PV	75	43	
2028	Unknown Solar	PV	75	43	
2029	Unknown 2	NG – CT	226	N/A	
2029	Unknown Solar	PV	75	43	
Total New MW			**1,856**	**754**	
Percentage of Solar MW Planned of Total New MW			**76%**		

Net Additions	**1,262**	

Source: 2020 Ten-Year Site Plan

[18] See Document No. 03509-2020, filed on July 1, 2020, in 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.*

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 2020 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

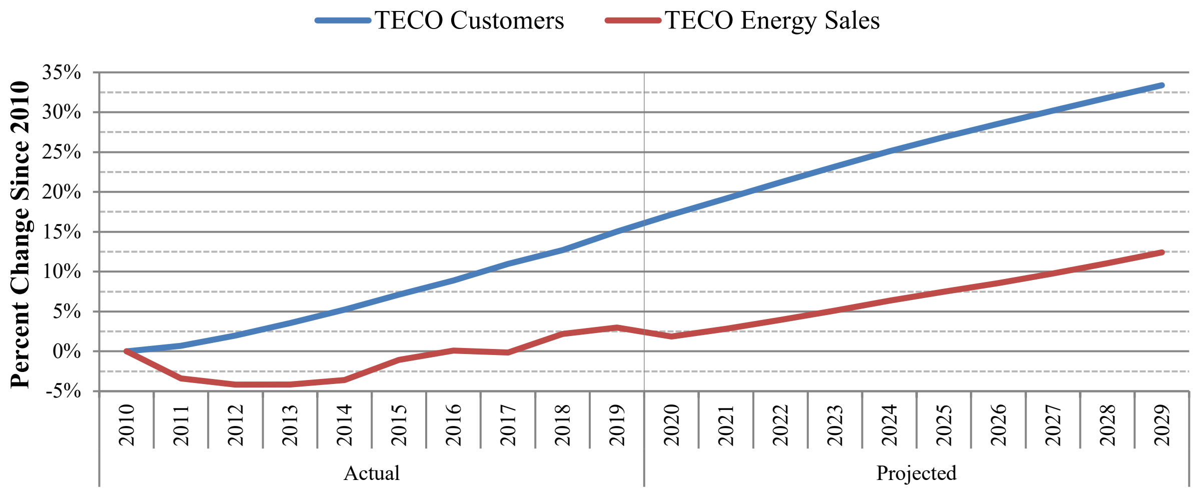
In 2019, TECO had approximately 771,960 customers and annual retail energy sales of 19,783 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 25 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, TECO's customer base has increased by 15.05 percent, while retail sales have increased by 2.97 percent.

In 2019, the utility's customer growth in the residential sector averaged 2.2 percent driven primarily by new construction and increasing net in-migration to its service area. Over the next 10 years, TECO expects its customer numbers will continue to grow at an average rate of 1.5 percent annually. The speed of growth would, however, slightly decrease each year for the entire forecasting period. The main driver behind these customer growth forecasts is the population projections prepared by the University of Florida's Bureau of Economic and Business Research (BEBR). Specifically, the projection of Hillsborough County's population is one of the primary explanatory variables in TECO's customer growth models.

In 2019, TECO's total annual retail energy sales was slightly higher than what was achieved in 2018. This is primarily attributed to the inclusion of a new phosphate mining load for a temporary period (2018 to 2020). Over the forecast horizon, TECO's retail energy sales growth will be lower than the customer growth. This trend is attributed to continued per-customer usage declines in the residential sector and declines in the phosphate sector as mining continues to move south, exiting the utility's service territory. The utility anticipates the average consumption per residential customer will decline at an average annual rate of 0.1 percent, primarily due to greater energy efficiencies of appliances, lighting, and new homes, as well as conservation efforts and changes in the housing mix.

Regarding the COVID-19 pandemic's impact, TECO experienced about 4 percent above normal residential energy sales for the period April to July 2020, but about 5 percent and 8 percent below normal commercial and industrial sales, respectively. In total, the impact to the retail energy sales is estimated to be a decline of approximately 2.4 percent. The utility indicated that assuming normal weather for the remainder of 2020 and 2021, its overall sales volumes would be slightly lower than the projections presented in its instant TYSP.

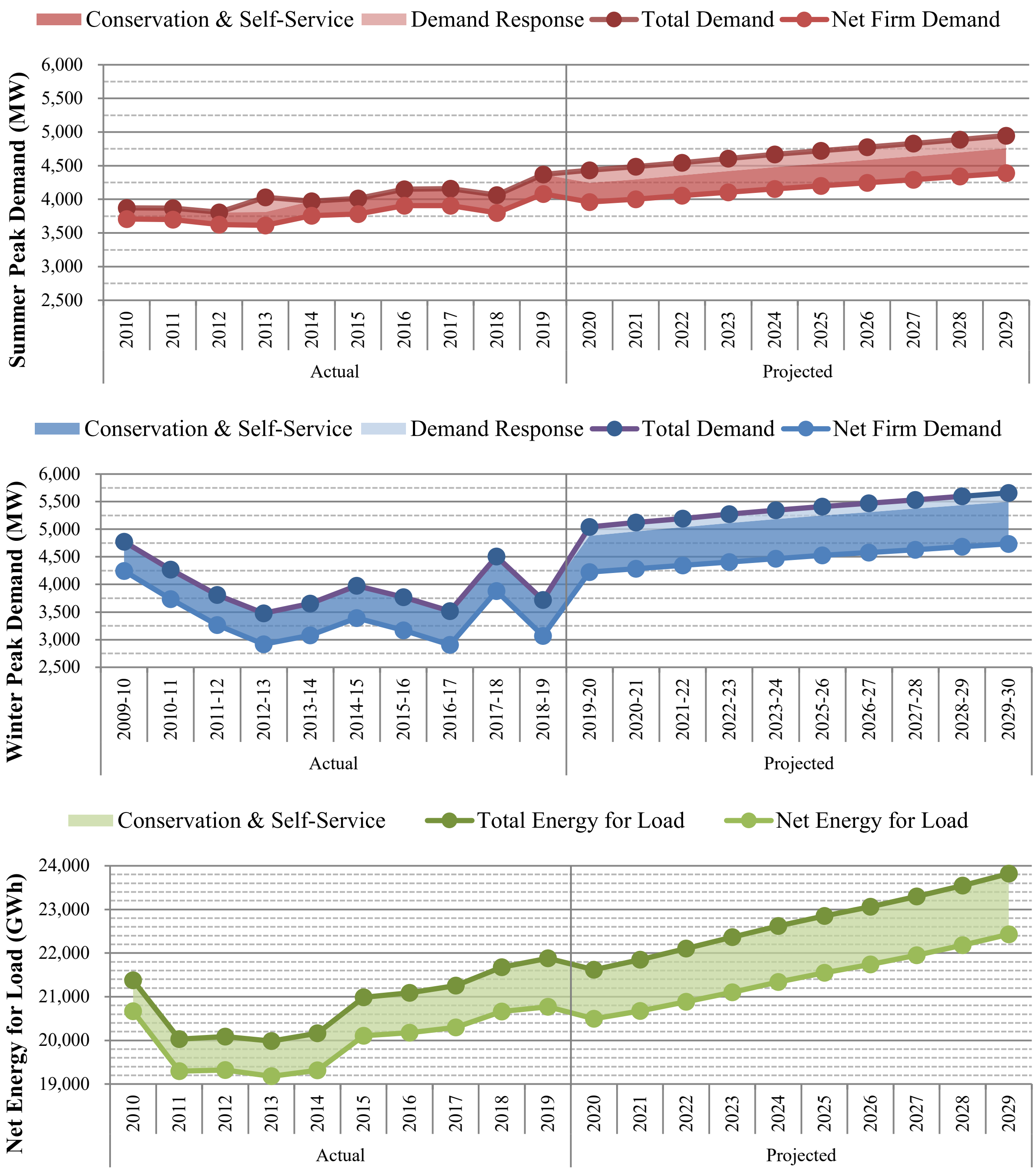
Figure 25: TECO Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 26 show TECO's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 2019, TECO continued operating within the 2015-2024 DSM Plan which supports the approved FPSC goals as required by FEECA. The utility's 2020 Ten-Year Site Plan reflects these goals.

Figure 26: TECO Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 shows TECO's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. Based on its 2020 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 84 percent of net energy for load. In the future, TECO projects that energy from coal will decrease and energy from natural gas will increase. TECO projects that renewable energy will increase from 3.6 percent to 12.9 percent by 2029. TECO projects the fifth highest percentage of renewable energy generation in 2029 of the TYSP Utilities.

Table 17: TECO Energy Generation by Fuel Type

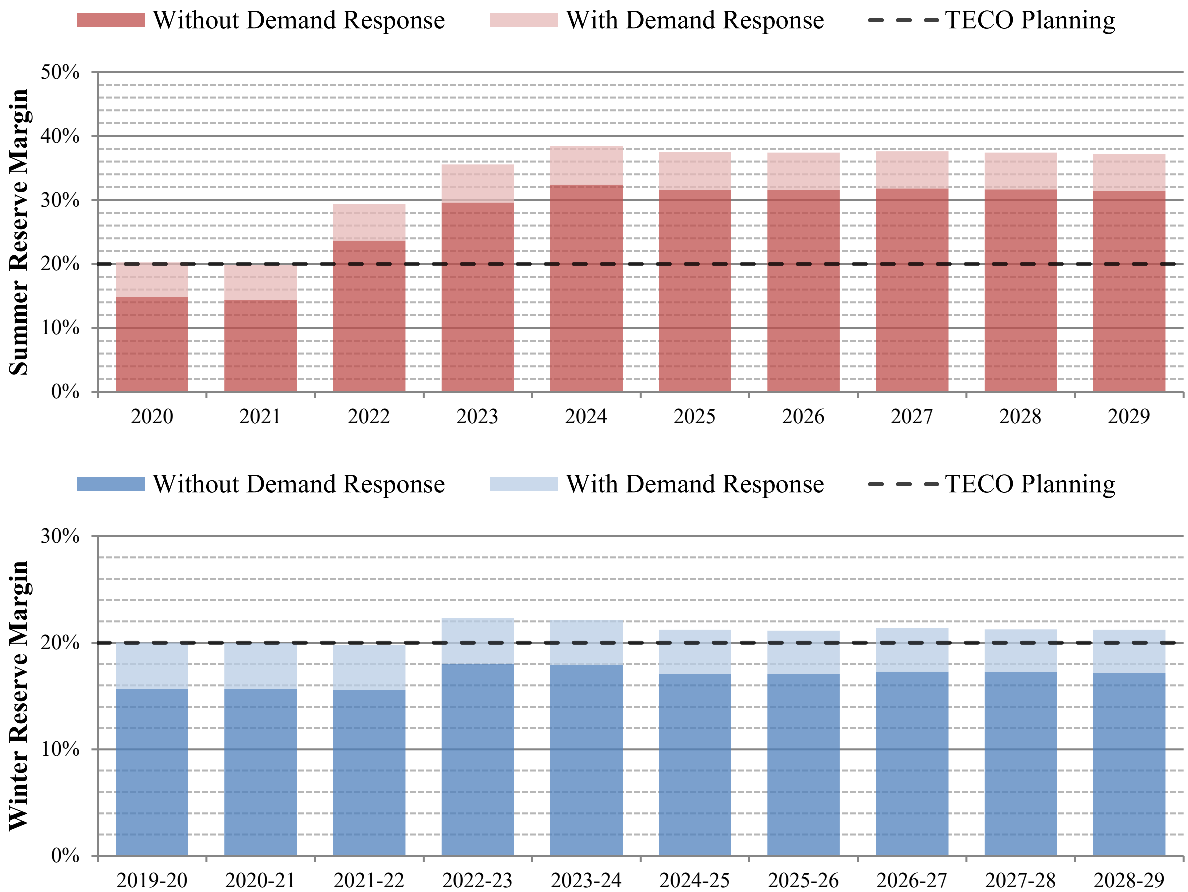
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	17,493	**84.2%**	18,981	**84.6%**
Coal	1,214	**5.8%**	444	**2.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	756	**3.6%**	2,902	**12.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	1,305	**6.3%**	103	**0.5%**
Total	**20,770**		**22,430**	

Source: 2020 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 27 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 in 2021. 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 27: TECO Reserve Margin Forecast



Source: 2020 Ten-Year Site Plan

Generation Resources

TECO plans a unit retirement and multiple unit additions during the planning period, as described in Table 18. TECO anticipates retiring its natural gas-fired Big Bend Unit 2 in 2021. TECO also plans to convert its stand-alone Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023. 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 655 MW of planned solar additions outside of the 149 MW of SoBRA units already approved by the Commission.[19] All planned solar additions make up approximately 43 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 plans to add 185 MW of reciprocating engines and 220 MW of battery storage. These additions are projected to yield improved environmental and reliability benefits, to enhance operational flexibility, and to improve system resiliency.

[19] Order No. PSC-2019-0477-FOF-EI, issued November 12, 2019, in Docket No. 20190136-EI, *In re: Petition for a limited proceeding to approve third SoBRA, by Tampa Electric Company.*

Table 18: 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	
Total Retirements			**385**	N/A	
New Units					
2020	Little Manatee River	PV	75	39	SoBRA units approved in Docket No. 20190136-EI.
2020	Wimauma	PV	75	43	
2021	Durrance	PV	60	35	
2021	Mountain View	PV	53	30	
2021	Future Solar 1 & 2	PV	95	53	
2021	Big Bend CT 5 & 6	NG – CT	660	N/A	
2021	Reciprocating Engine 1-5	NG – IC	93	N/A	
2022	Battery Storage 1-3	BAT	30	N/A	
2022	Future Solar 3-5	PV	224	125	
2023	Future Solar 6-8	PV	224	125	
2025	Reciprocating Engine 6	NG – IC	19	N/A	
2025	Battery Storage 4	BAT	10	N/A	
2026	Battery Storage 5-10	BAT	60	N/A	
2027	Reciprocating Engine 7-10	NG – IC	74	N/A	
2028	Battery Storage 11-16	BAT	60	N/A	
2029	Battery Storage 17-22	BAT	60	N/A	
Total New Units			**1,869**	**450**	
Percentage of Solar MW Planned of Total New MW			**43%**		
Net Additions			**1,484**		

Source: 2020 Ten-Year Site Plan

Florida Municipal Power Agency (FMPA)

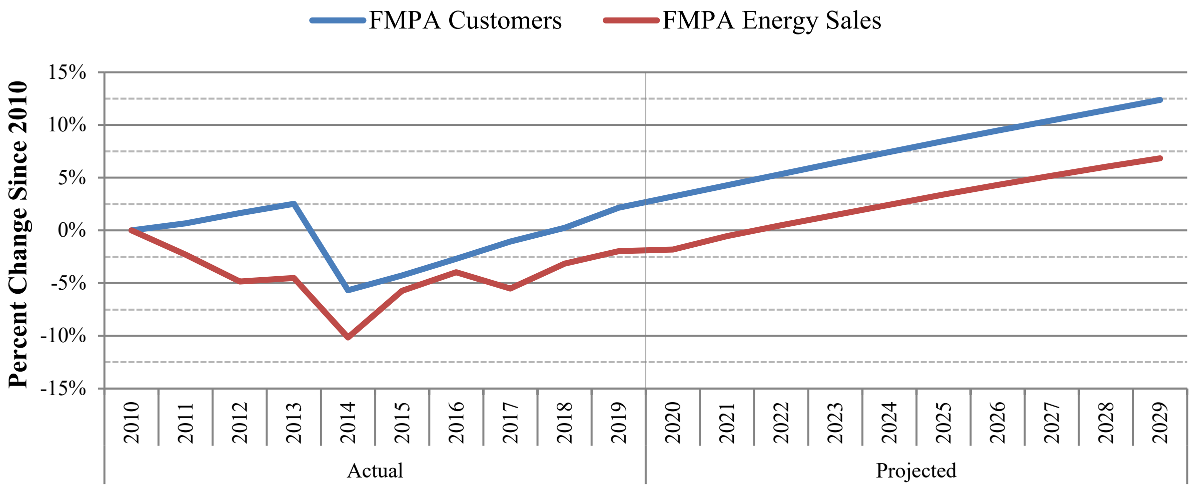
FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants in 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. 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 FMPA's 2020 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2019, FMPA had approximately 266,101 customers and annual retail energy sales of 5,842 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 28 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, FMPA's customer base has increased by 2.16 percent, while retail sales have decreased by 1.95 percent. As illustrated, FMPA's retail energy sales growth rate is anticipated to exceed its historic 2010 peak in 2022.

From the start of the COVID-19 pandemic effects on the U.S., FMPA assumed a 5 percent decrease in energy sales for the remainder of the fiscal year on a weather-normalized basis. In March 2020, energy sales were above projected, driven in large part by weather. For April 2020, energy sales were approximately 1.2 percent above projected. When adjusted for weather, sales are approximately 2 to 3 percent below budget, attributable to the impact of the pandemic. Although recent data is more encouraging than FMPA's conservative planning estimate of 5 percent sales reduction, the utility is continuing to assume approximately 5 percent sales decline, on a weather adjusted basis, for the remainder of 2020. For 2021, FMPA also expects lower energy sales compared to what is projected in its 2020 TYSP. The utility will continue to monitor the sales on a daily basis and adjust future projections as appropriate.

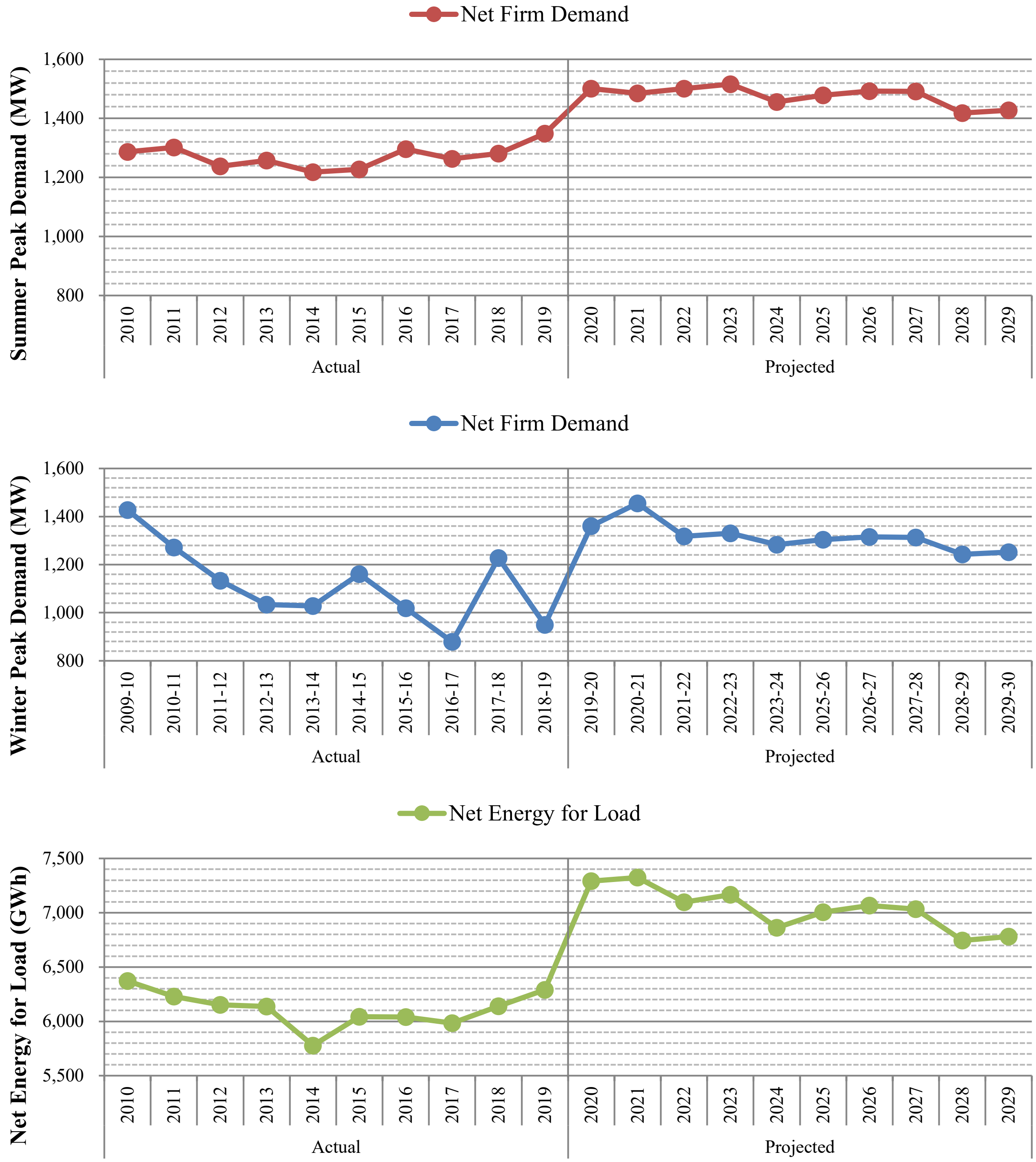
Figure 28: FMPA Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 29 show FMPA's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 29: FMPA Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows FMPA's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects a decrease in energy generation from coal in 2029, but approximately 87 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 19: FMPA Energy Generation by Fuel Type

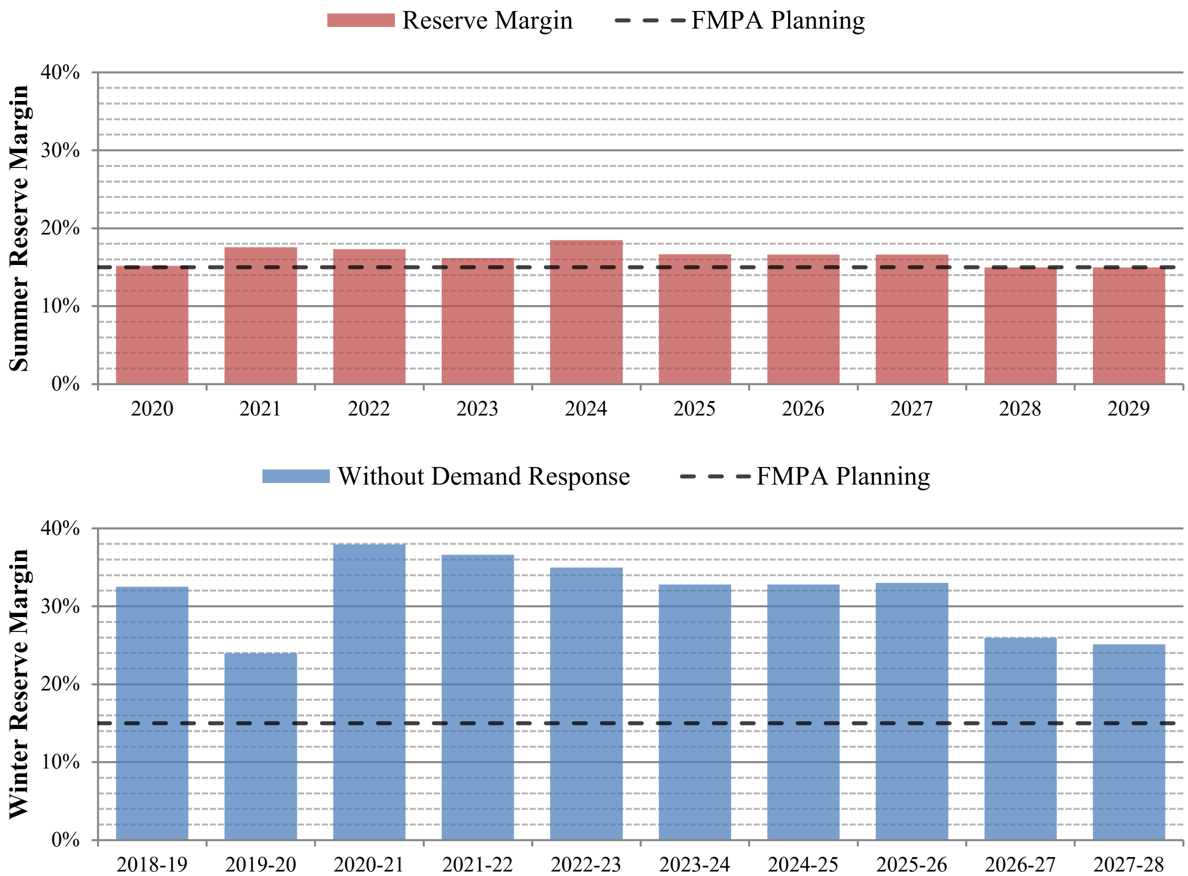
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	4,757	**75.6%**	5,507	**81.2%**
Coal	1,121	**17.8%**	403	**5.9%**
Nuclear	368	**5.9%**	399	**5.9%**
Oil	3	**0.0%**	0	**0.0%**
Renewable	41	**0.7%**	472	**7.0%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**6,290**		**6,781**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 30 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 30: FMPA Reserve Margin Forecast



Source: 2020 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 2020 Ten-Year Site Plan suitable for planning purposes.

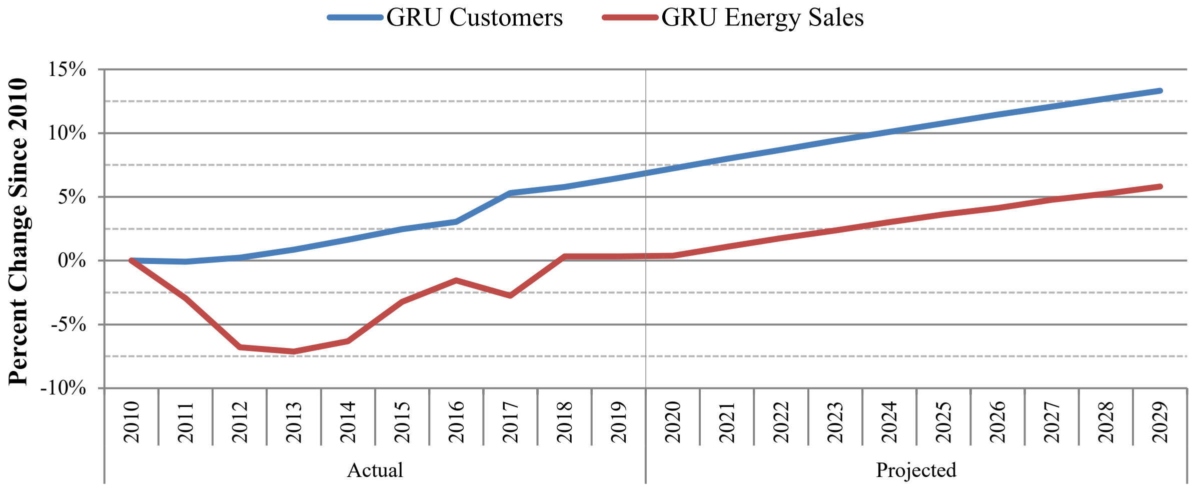
Load & Energy Forecasts

In 2019, GRU had approximately 98,324 customers and annual retail energy sales of 1,830 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Figure 31 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010.

Over the last 10 years, GRU's customer base has increased by 6.48 percent, while retail sales have increased by 0.33 percent. The utility reported consumption per residential and non-residential customers declined 0.85 percent and 0.7 percent per year, respectively, over the past 10 years. It believed that some of the factors effecting the per-customer consumption reduction include the 2007-2008 recession, increased electricity price, improved building envelopes, as well as energy standards (regulatory) and measures (utility). For the next 10 years, the projected consumption per residential and non-residential customers are projected to decline 0.21 percent and 0.19 percent per year, respectively.

To project the impacts of the COVID-19 pandemic, GRU made subjective adjustments to its forecasts of customers and sales. The adjustments were made to each month from April 2020 through December 2020 such that projected impacts ramped up during April and May, held constant through September, and then diminished gradually from October through December. By January 2021, GRU resumes its base case forecast trajectory. The primary contingency within this set of assumptions is that the University of Florida resumes live classes by early September and that the home football schedule resembles its original plan. Based upon these adjustments, GRU projects its total retail sales would decrease 2.2 percent for the utility's 2020 fiscal year (October through September) and decrease 0.8 percent for its 2021 fiscal year.

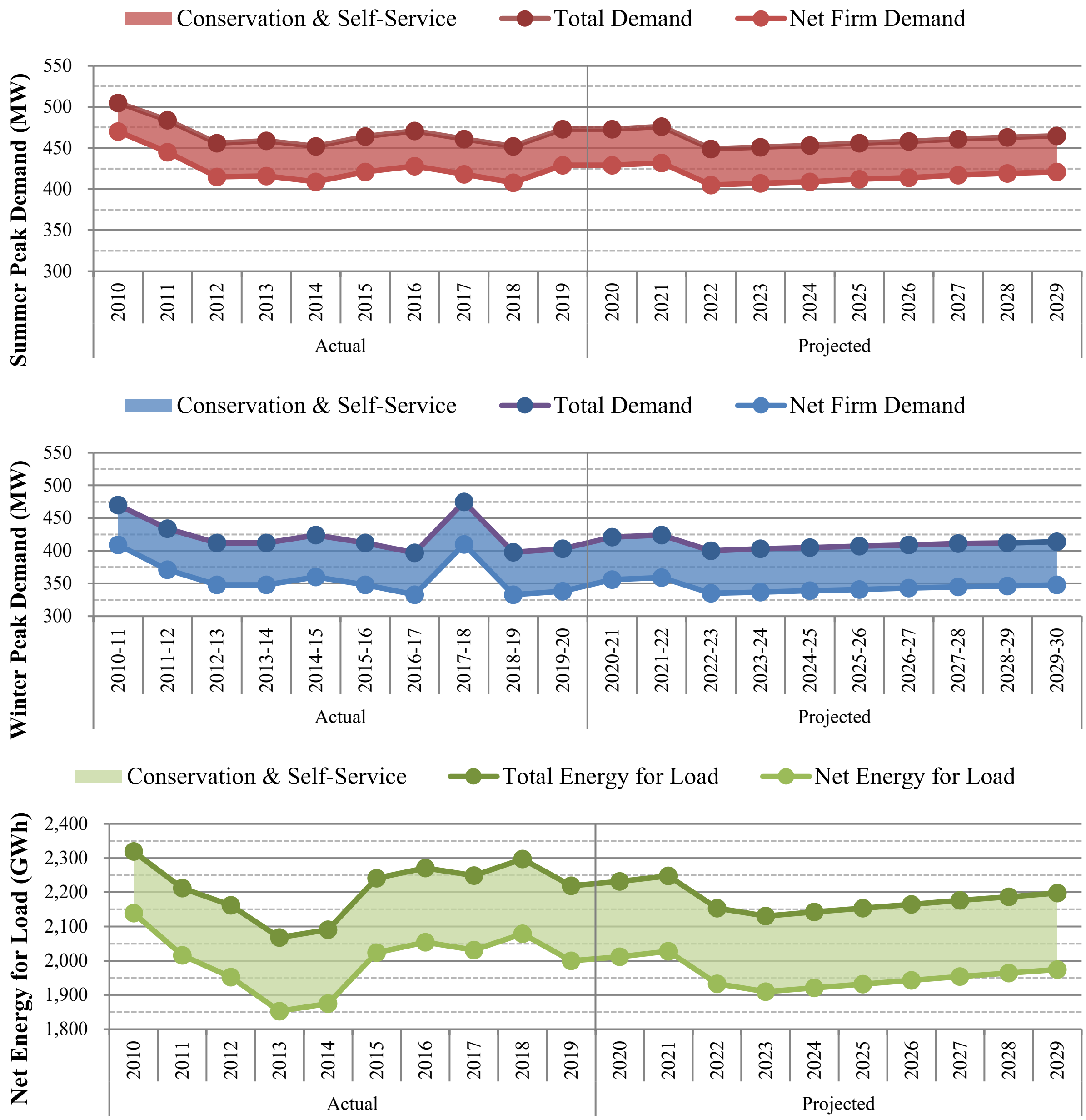
Figure 31: GRU Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 32 show GRU's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 32 include the impact of these demand-side management programs.

Figure 32: GRU Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 20 shows GRU's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. In 2019, natural gas was the primary fuel followed by renewables and coal respectively. By the year 2029, renewables are expected to drop in usage while the energy obtained by burning coal and natural gas is expected to increase.

Table 20: GRU Energy Generation by Fuel Type

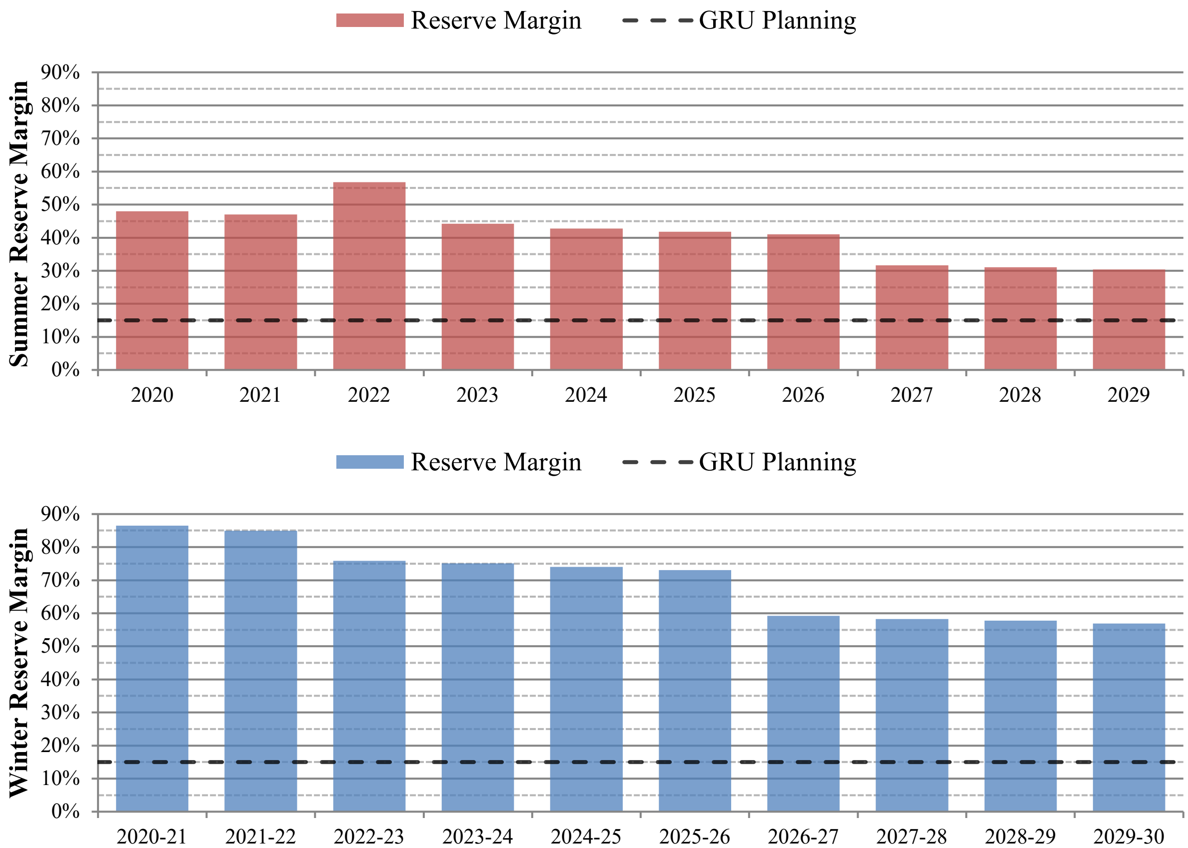
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	854	**42.7%**	952	**48.2%**
Coal	449	**22.5%**	616	**31.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	8	**0.4%**	0	**0.0%**
Renewable	617	**30.9%**	335	**17.0%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	72	**3.6%**	71	**3.6%**
Total	**2,000**		**1,974**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 33 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. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represented 53 percent of its summer net firm peak demand in 2019.

Figure 33: GRU Reserve Margin Forecast



Source: 2020 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 21. As a smaller utility, single units can have a large impact upon reserve margin.

Table 21: 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: 2020 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 2020 Ten-Year Site Plan suitable for planning purposes.

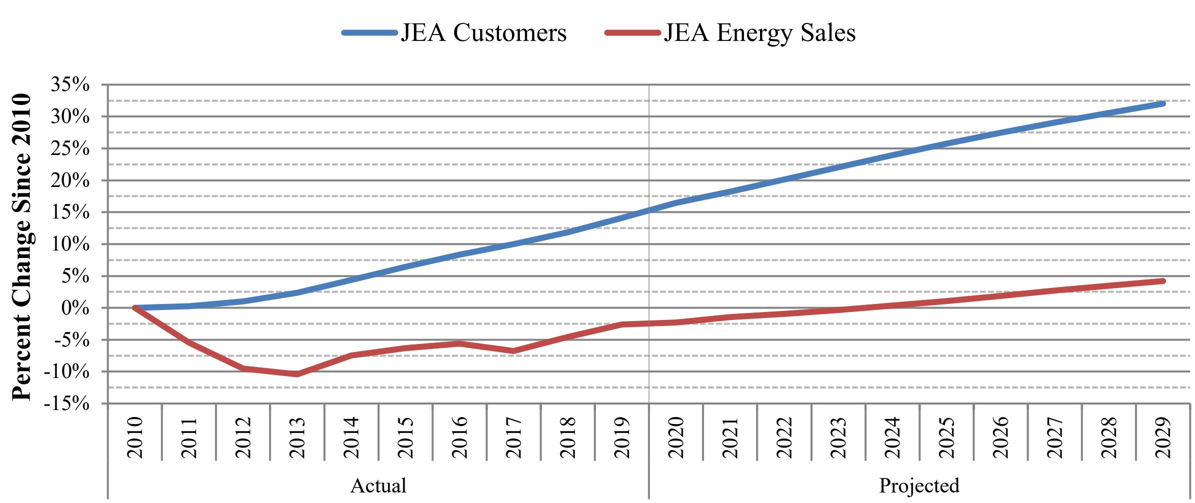
Load & Energy Forecasts

In 2019, JEA had approximately 474,178 customers and annual retail energy sales of 12,328 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Figure 34 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, JEA's customer base has increased by 14.13 percent, while retail sales have decreased by 2.62 percent. As illustrated, JEA's retail energy sales are not anticipated to exceed its historic 2010 peak until 2024.

For the instant TYSP, JEA's projected growth rate of the annual average total customers would reach a peak in 2022-2024 then start to decrease each year for the rest of the forecasting period. The utility explained that this trend is dictated by Moody's housing start data and commercial employment data which are the base for JEA's forecast of customer growth.

JEA has performed monthly studies to capture potential COVID-19 pandemic impacts. The utility's actual sales data for March through June 2020 shows that residential sales increased about 1 percent while commercial and industrial sales declined about 12 percent and 5 percent, respectively. JEA's overall sales reduced 5 percent for these four months as compared to its 2019 actual sales. The utility expects its total projected sales to decline by 1.2 percent compared with the projections in 2020 TYSP, and anticipates the pandemic to continuously impact the energy sales for at least two years before recovering to follow the original forecast trend.

Figure 34: JEA Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 35 show JEA's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 35: JEA Demand and Energy Forecasts

Source: 2020 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 2020 Ten-Year Site Plan reflects these goals.

Fuel Diversity

Table 22 shows JEA's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. While natural gas was the dominant fuel source in 2019, coal was JEA's second most utilized fuel source. JEA's 2020 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 2029.

Table 22: JEA Energy Generation by Fuel Type

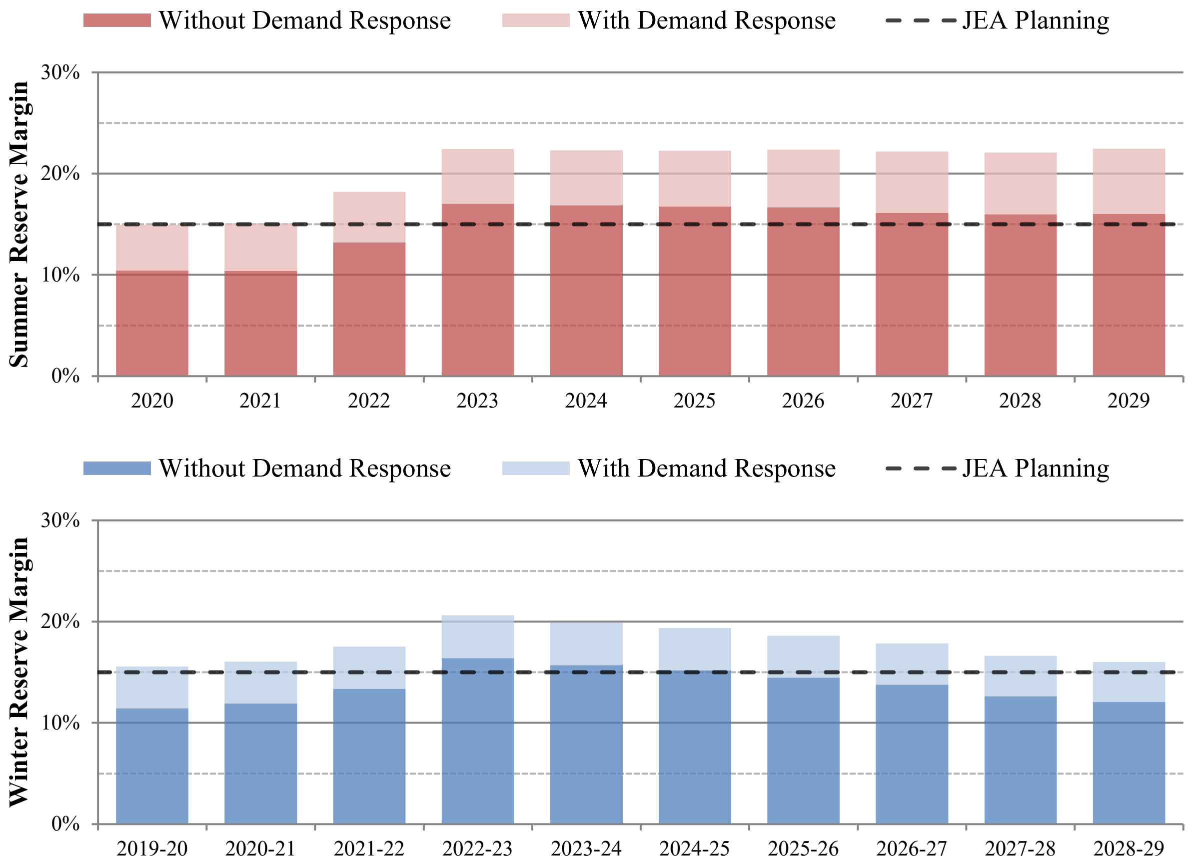
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	6,312	**49.3%**	6,240	**45.5%**
Coal	3,287	**25.7%**	5,121	**37.4%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	3	**0.0%**	1	**0.0%**
Renewable	146	**1.1%**	663	**4.8%**
Interchange	3,050	**23.8%**	1,679	**12.3%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,798**		**13,704**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. As shown in the figure, JEA's generation needs begin to be controlled by its winter peak in 2023. 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 36: JEA Reserve Margin Forecast



Source: 2020 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 2020 TYSP.

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 2020 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

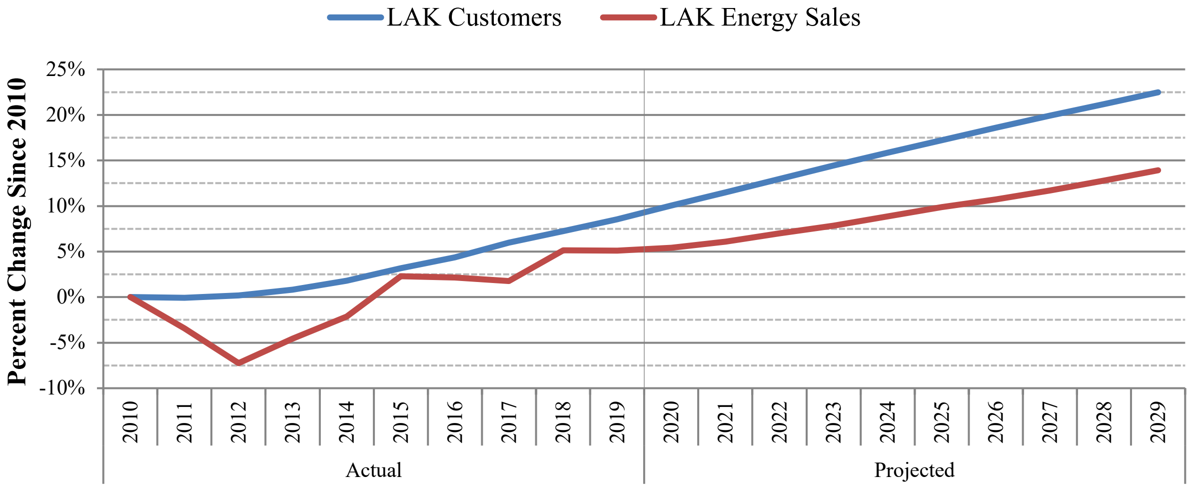
In 2019, LAK had approximately 132,217 customers and annual retail energy sales of 3,117 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 37 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, LAK's customer base has increased by 8.54 percent, while retail sales have grown by 5.09 percent.

For the instant TYSP, LAK projected that the growth rate of annual average customers would decrease slightly each year after 2020 for the entire forecasting period. The utility indicated that this result was based on the Moody's Economic.com household forecast of Lakeland-Winter Haven area which LAK used as the major input of its residential customer forecasting model. For its commercial and industrial forecast, LAK used the forecasted moving average of the residential customers as its input. Thus, these forecasts are also indirectly based on the same Moody's household forecast.

The utility projected that the growth rate of energy sales will lag behind the projected growth rate of customers. As illustrated in the figure, the divergence is projected to increase marginally. The main attributable factors are the decreased sales in residential and commercial sectors resulting from improved energy efficiency. The average KWh consumptions in these sectors have been declining, and the trends are expected to continue. The main contributing factors to the decline in the residential sector are the increased appliance energy efficiency, improved building shell insulation, and changes in building type mix. The main causes to the decline in the commercial sector are the lighting upgrades, appliance energy efficiency, and the impact of the LAK's energy management system.

LAK has been aggregating AMI hourly meter interval data to track the COVID-19 pandemic impacts. The utility's actual sales data generated in mid-June 2020 (weather normalized), for the period mid-March through mid-May of 2020, averaged 6 percent higher than forecasted for the residential sector, but averaged 19 percent and 11 percent lower than forecasted for the commercial and industry sectors, respectively. LAK also disclosed that, for the last weeks in May 2020, while business were gradually being allowed to reopen, this pattern of sales data was changed to 4 percent higher than forecasted for the residential customers, but 12 percent and 9 percent lower than forecasted for the commercial and industrial customers, respectively. As of mid-July 2020, LAK's total cumulative calendar year actual sales (weather normalized) were at a negative 2.1 percent compared to what was originally projected in 2020 TYSP. Assuming the same trend continues, the utility expects that its weather normalized total sales are likely to end up in the 3 percent to 5 percent lower-than forecast range for the 2020 through 2022 timeframe.

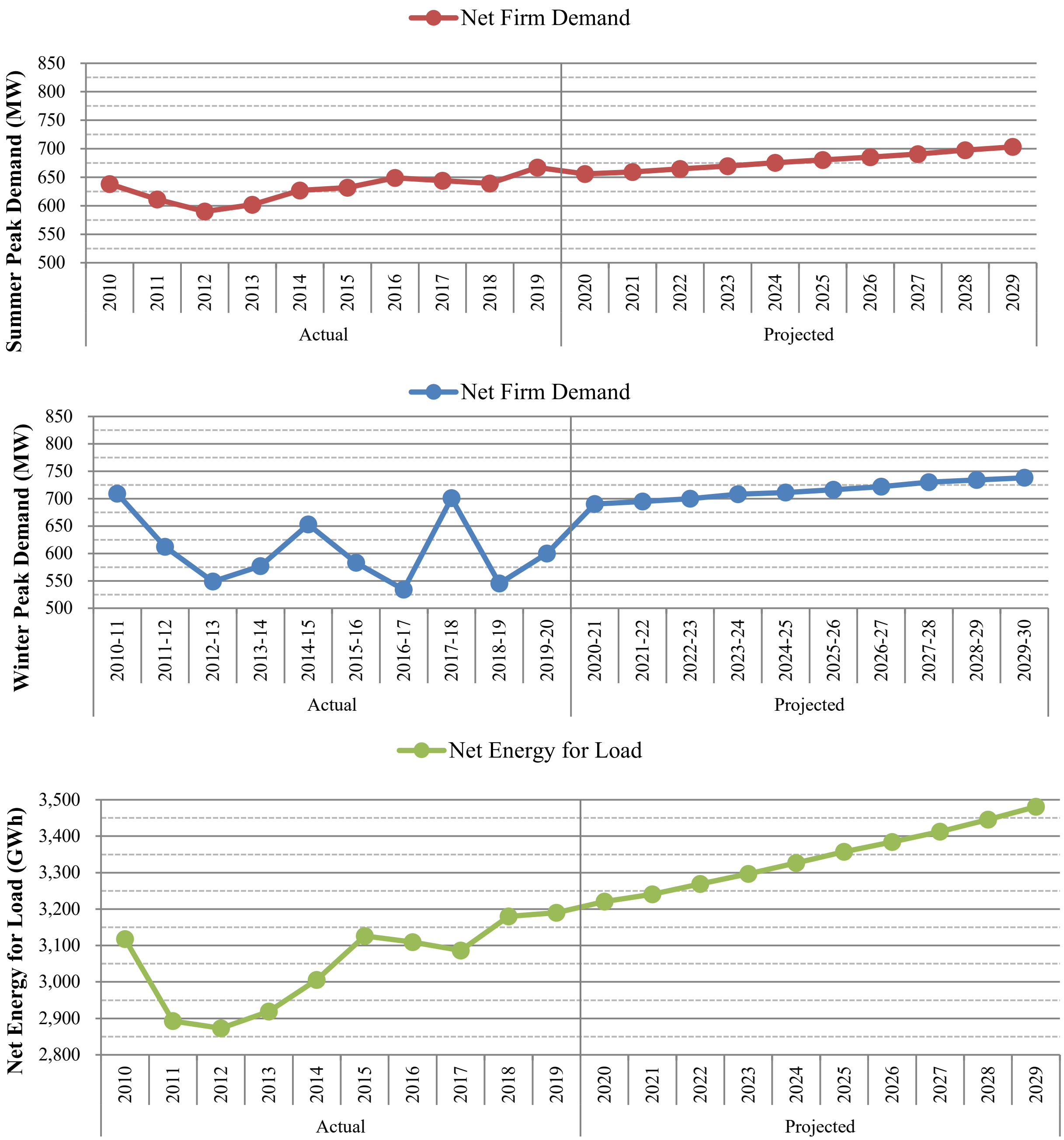
Figure 37: LAK Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 38 show LAK's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 38: LAK Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 23 shows LAK's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. LAK uses natural gas as its primary fuel type for energy, with coal representing about 17 percent net energy for load. While natural gas generation is anticipated to decrease, coal is projected to increase by 2029.

Table 23: LAK Energy Generation by Fuel Type

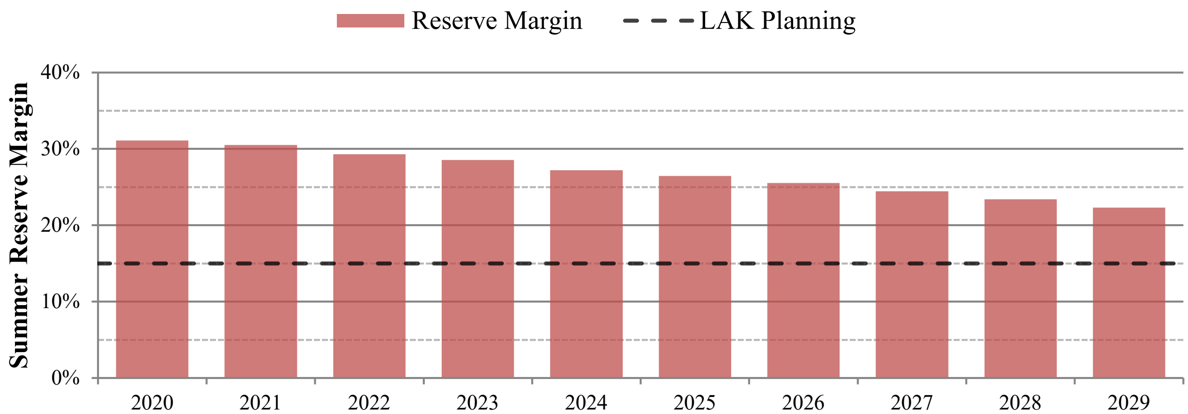
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	2,382	**74.7%**	1,767	**50.8%**
Coal	548	**17.2%**	1,003	**28.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	28	**0.9%**	28	**0.8%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	231	**7.2%**	682	**19.6%**
Total	**3,189**		**3,481**	

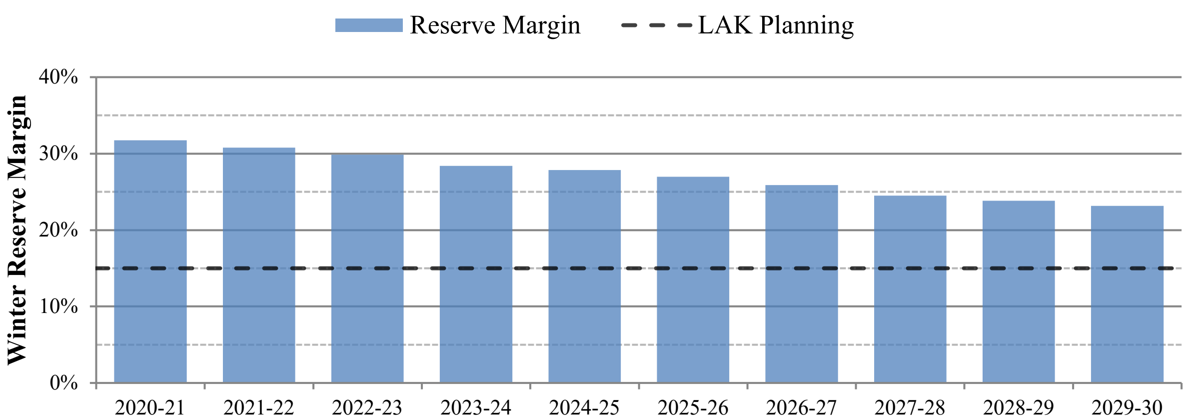
Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 39 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 51 percent of summer net firm peak demand in 2019.

Figure 39: LAK Reserve Margin Forecast





Source: 2020 Ten-Year Site Plan

Generation Resources

LAK plans on adding a natural gas combustion turbine and retiring a natural gas steam turbine as shown in Table 24.

Table 24: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2020	C.D. McIntosh 2	NG-ST	106
New Units			
2020	C.D. McIntosh GT 2	NG-CT	115
Net Additions			**9**

Source: 2020 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 2020 Ten-Year Site Plan suitable for planning purposes.

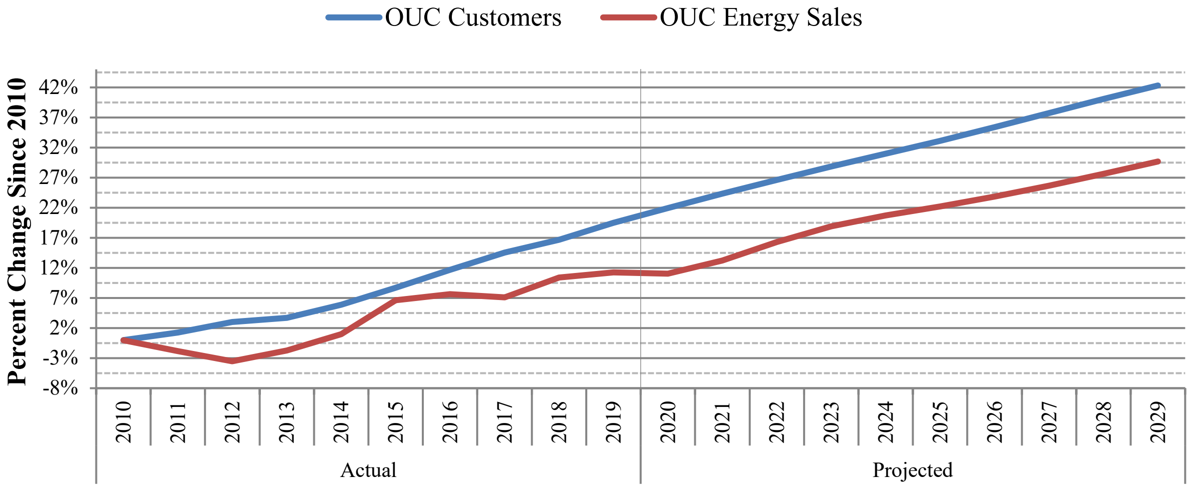
Load & Energy Forecasts

In 2019, OUC had approximately 247,443 customers and annual retail energy sales of 6,823 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's retail sales has an average annual growth of 1.5 percent. Figure 40 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010.

Over the last 10 years, OUC's customer base has increased by 19.5 percent, while retail energy sales have increased by 11.3 percent, approximately. The utility expects a continued growth in retail sales at an average annual rate of 1.7 percent for the current forecast horizon. OUC noted that the main drivers for a higher growth rate of retail energy sales than the past growth rate are due to projected growth in electric vehicle charging load and major commercial expansions from Universal Studios and the Orlando International Airport.

To account for the impact of the COVID-19 pandemic, OUC has rerun its forecasts with some revisions to the forecasts that were used in its 2020 TYSP. These revisions include: (1) updating the forecasted number of commercial customers and Orlando employment projections that were based on HIS Markit's April 2020 economic and demographic projections; and (2) adjusting the timing and/or loads associated with a portion of the planned large commercial expansions (outside of normal growth) in accordance with recent announcements of delays. The new forecast reduces the utility's average annual growth rate in total retail energy sales from 1.7 percent to 1.6 percent, for the 10-year forecast period ending 2029.

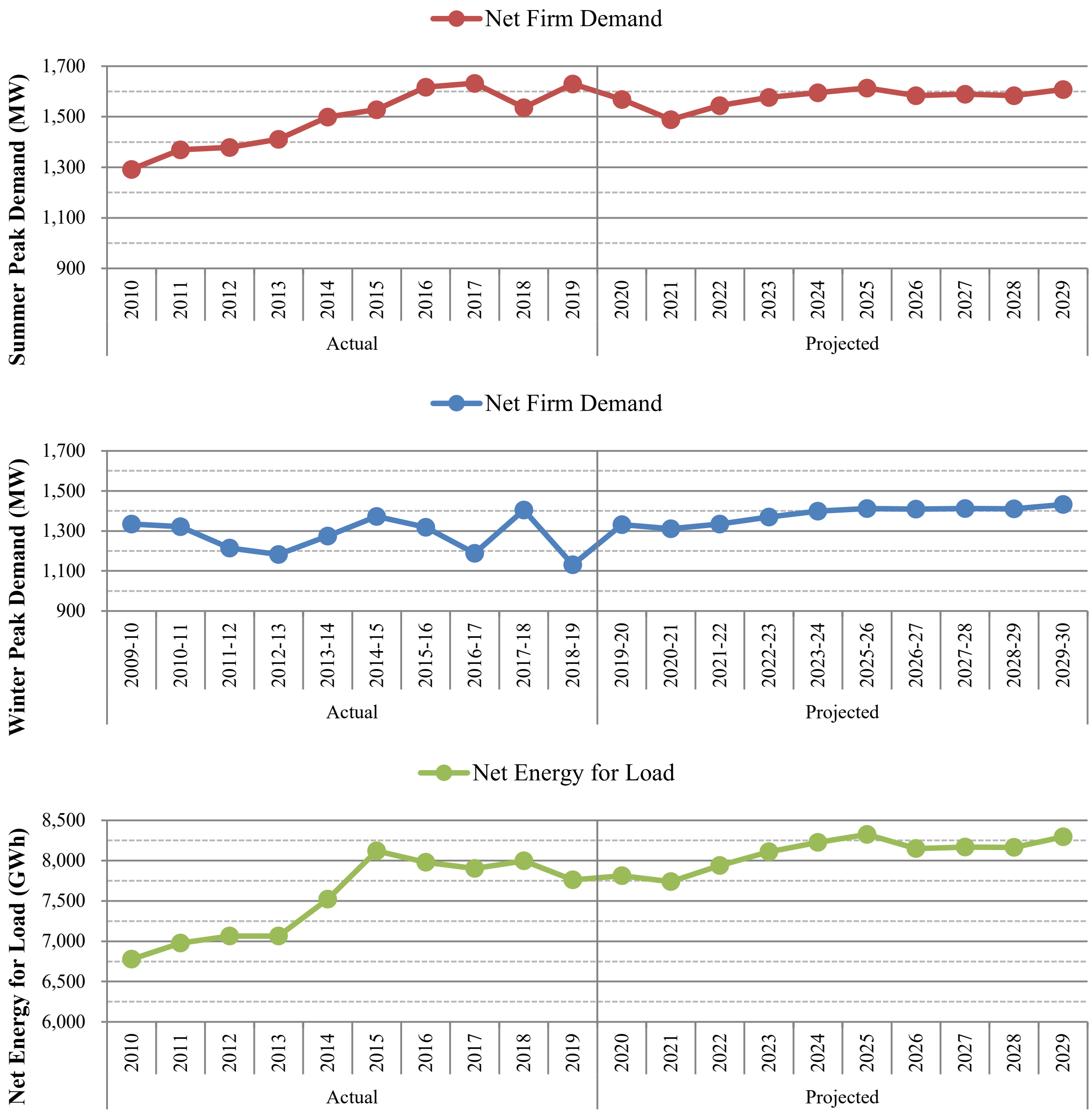
Figure 40: OUC Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 41 show OUC's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 2020 Ten-Year Site Plan reflects these goals.

Figure 41: OUC Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 shows OUC's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. In 2019, approximately 47 percent of OUC's net energy for load was met with coal, while natural gas, the second most-used fuel, met 46 percent. By 2029, OUC projects an increase in renewable energy generation from 2 percent to 13 percent, while coal generation is expected to decrease from 46 percent to 39 percent.

Table 25: OUC Energy Generation by Fuel Type

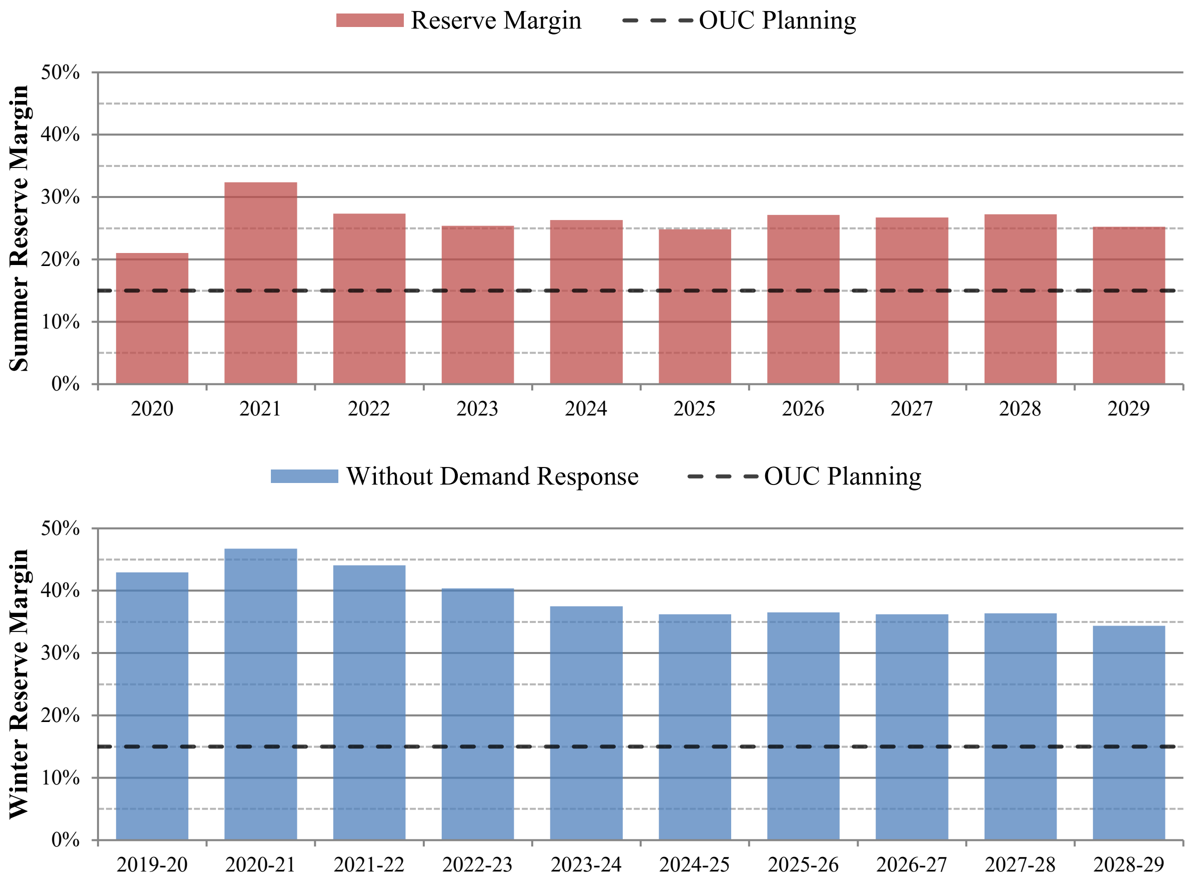
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	3,554	**45.8%**	3,405	**41.0%**
Coal	3,614	**46.6%**	3,250	**39.2%**
Nuclear	449	**5.8%**	554	**6.7%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	145	**1.9%**	1,086	**13.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,762**		**8,295**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 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 throughout the planning period.

Figure 42: OUC Reserve Margin Forecast



Source: 2020 Ten-Year Site Plan

Generation Resources

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

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 2020 Ten-Year Site Plan suitable for planning purposes.

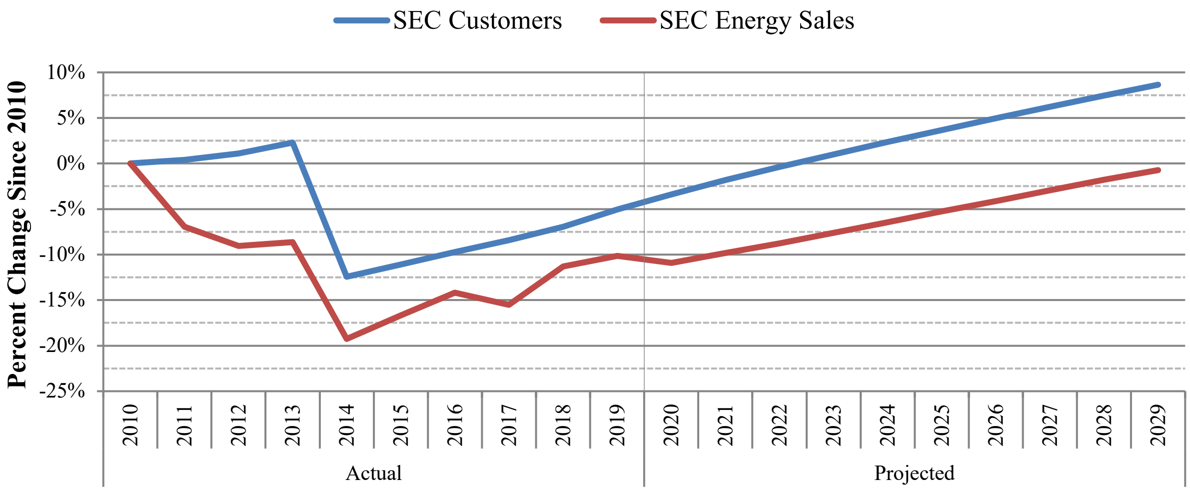
Load & Energy Forecasts

In 2019, SEC member cooperatives had approximately 802,892 customers and annual retail energy sales of 14,425 GWh or approximately 6.2 percent of Florida's annual retail energy sales. Figure 43 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, SEC's customer base has decreased by 5.07 percent, and retail sales have decreased by 10.14 percent. As illustrated in the figure, SEC's retail energy sales are not anticipated to exceed its historic 2010 peak during this planning period. The substantial decline in customer growth that occurred in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

SEC's energy sales forecast is based upon population growth projected by BEBR at the University of Florida, the utility's recent data of energy consumption, and Florida's county-level monthly economic information from Moody's Analytics. SEC indicated that the number of customers in its service areas are expected to decline in the latter half of the current TYSP forecast period, primarily due to slowing migration of "baby boomers."

From March through June 2020, SEC's energy sales have been above the projected amounts. The utility reported that the COVID-19 pandemic has had little impact on its load for this time period. SEC indicated that based on its latest projections of the pandemic's effect, the Total Sales to Ultimate Customers in 2020 and 2021 are estimated to be slightly higher than the projections presented in its original 2020 TYSP.

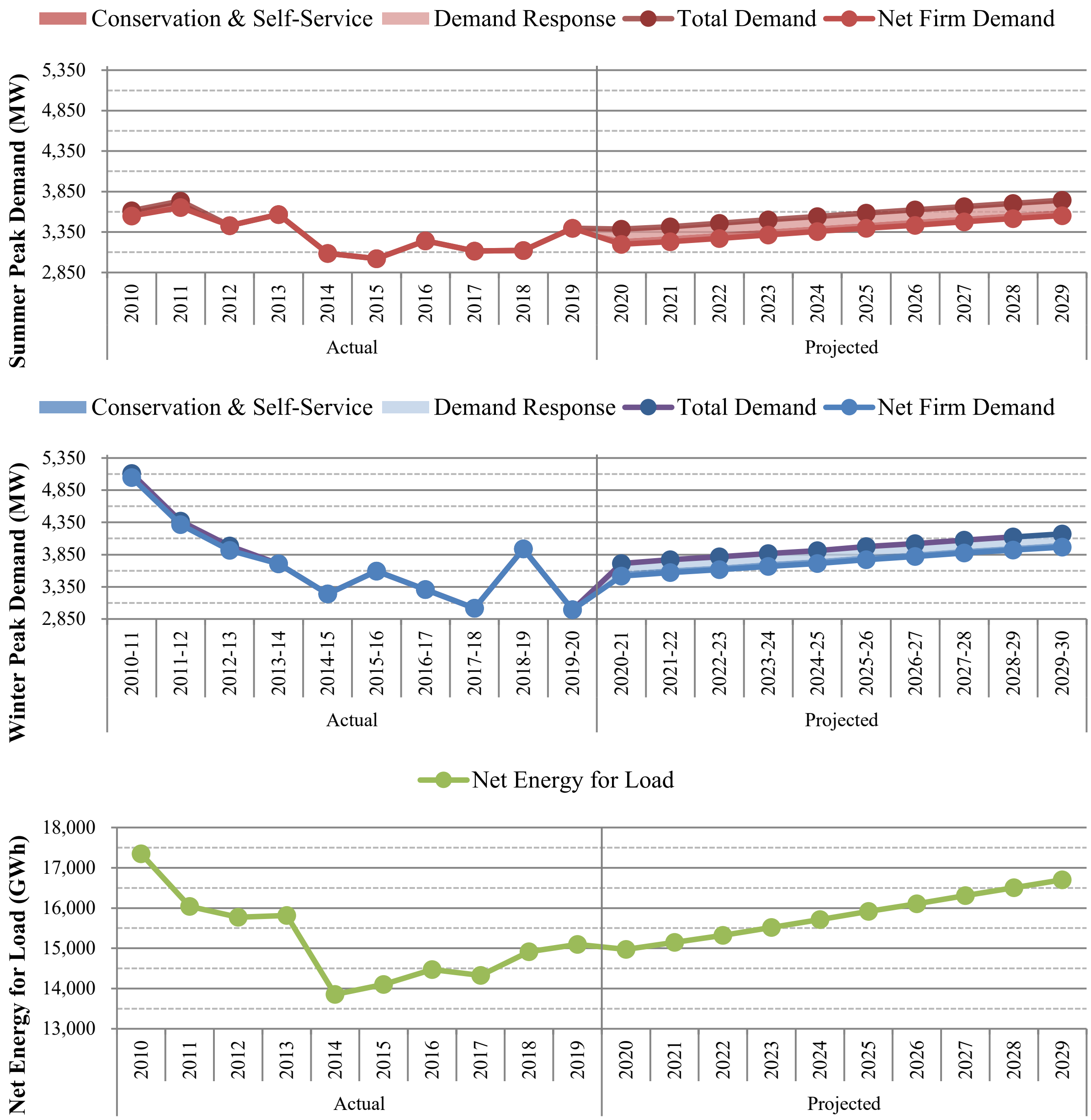
Figure 43: SEC Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 44 show SEC's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 44.

Figure 44: SEC Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 26 shows SEC's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. In 2019, SEC used coal as its primary source of fuel, while natural gas was the second most used fuel. By 2029 natural gas usage is expected to become the primary fuel source.

Table 26: SEC Energy Generation by Fuel Type

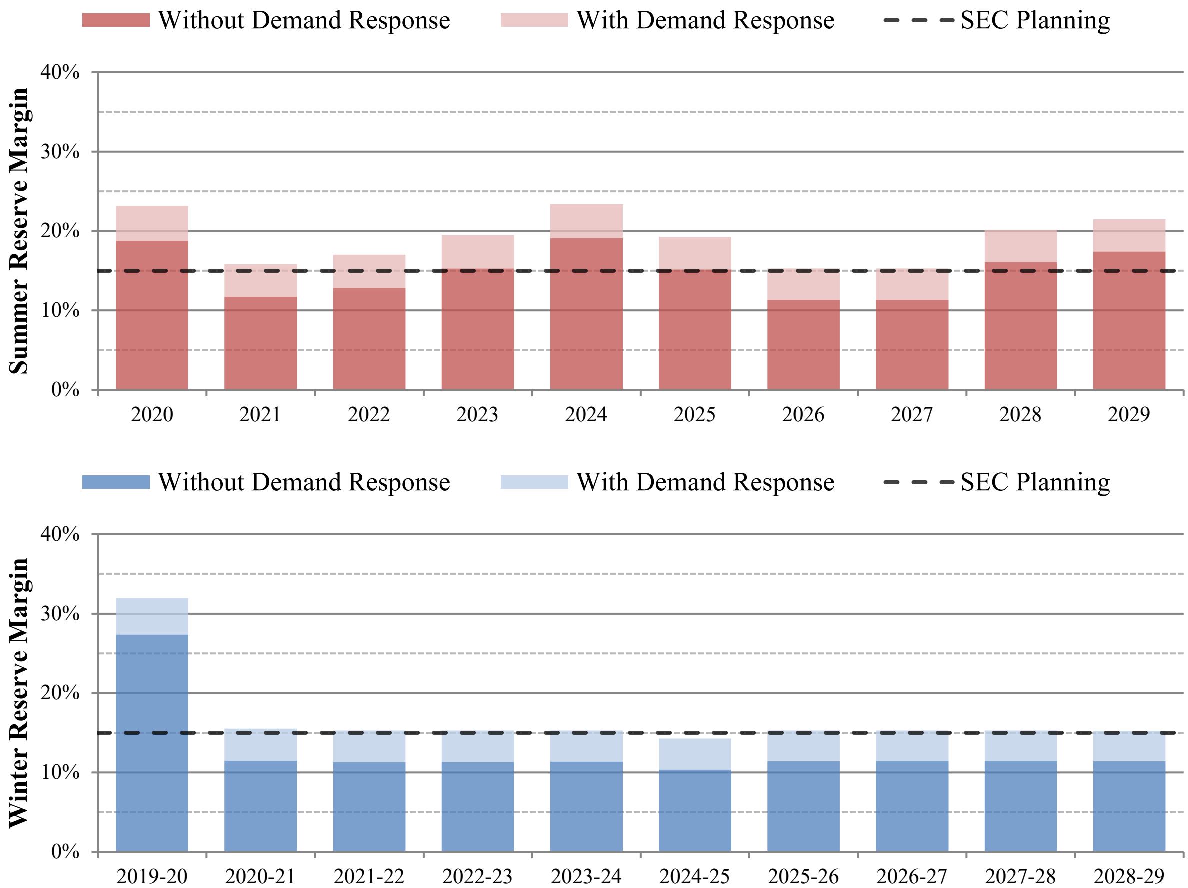
Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	3,745	**24.8%**	9,868	**59.1%**
Coal	6,952	**46.1%**	2,677	**16.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	18	**0.1%**	7	**0.0%**
Renewable	595	**3.9%**	768	**4.6%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	3,785	**25.1%**	3,383	**20.3%**
Total	**15,095**		**16,703**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 45 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 45: SEC Reserve Margin Forecast



Source: 2020 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add three units during the planning period, as described in Table 27. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[20] 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. Two unnamed reciprocating units are to come online 2027 and 2028.

Table 27: 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	1,108	Docket No. 20170266-EC
2027	Unnamed Reciprocating Unit	NG - IC	92	
2028	Unnamed Reciprocating Unit	NG - IC	92	
Total New Units			**1,292**	
Net Additions			**658**	

Source: 2020 Ten-Year Site Plan

[20] 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.*

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 2020 Ten-Year Site Plan suitable for planning purposes.

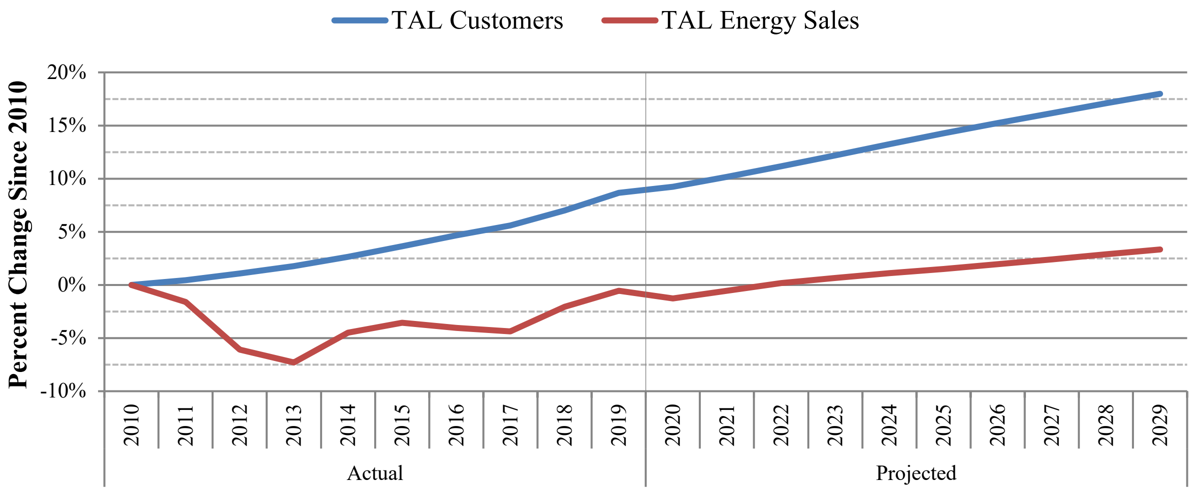
Load & Energy Forecasts

In 2019, TAL had approximately 123,538 customers and annual retail energy sales of 2,739 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 46 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2010. Over the last 10 years, TAL's customer base has increased by 8.66 percent, while retail sales have decreased by 0.55 percent. As illustrated in the figure, TAL's retail energy sales are not anticipated to exceed its historic 2010 peak until 2022.

TAL's 2020 TYSP customer growth forecast incorporates economic and demographic projections for Leon County based on a blend of information from Woods and Poole Economics (W&P) and BEBR. Information from these sources reflected a projected compound annual growth rate for population, household counts, employment, and average income. This population projection represents a slightly lower growth rate than what was used in the 2019 TYSP, which was based on a similar blend of information from W&P and BEBR's 2018 population forecast for the same 10-year period. Consequently, TAL's customer growth rate forecast for the instant TYSP is marginally lower than the growth rate calculated using data from the 2019 TYSP.

TAL has been monitoring the ongoing impacts of the COVID-19 pandemic on monthly sales by rate class and total sales since March 1, 2020. Its residential sales have increased as some of the local population began teleworking from home. In contrast, commercial sales have declined due to a combination of increased teleworking and a reduction in business activities. The utility estimates that total sales have declined and that, as some residents have returned to work, such decline has diminished to a certain extent. TAL expects that actual Sales to Ultimate Customers in 2020 and 2021 will likely be reduced compared to the projections in its 2020 TYSP. It notes, however, there is a good deal of uncertainty regarding the magnitude and timing of the COVID-19-caused impacts. TAL notes that these impacts will be affected by the success of containing the pandemic and the pace of the economic recovery.

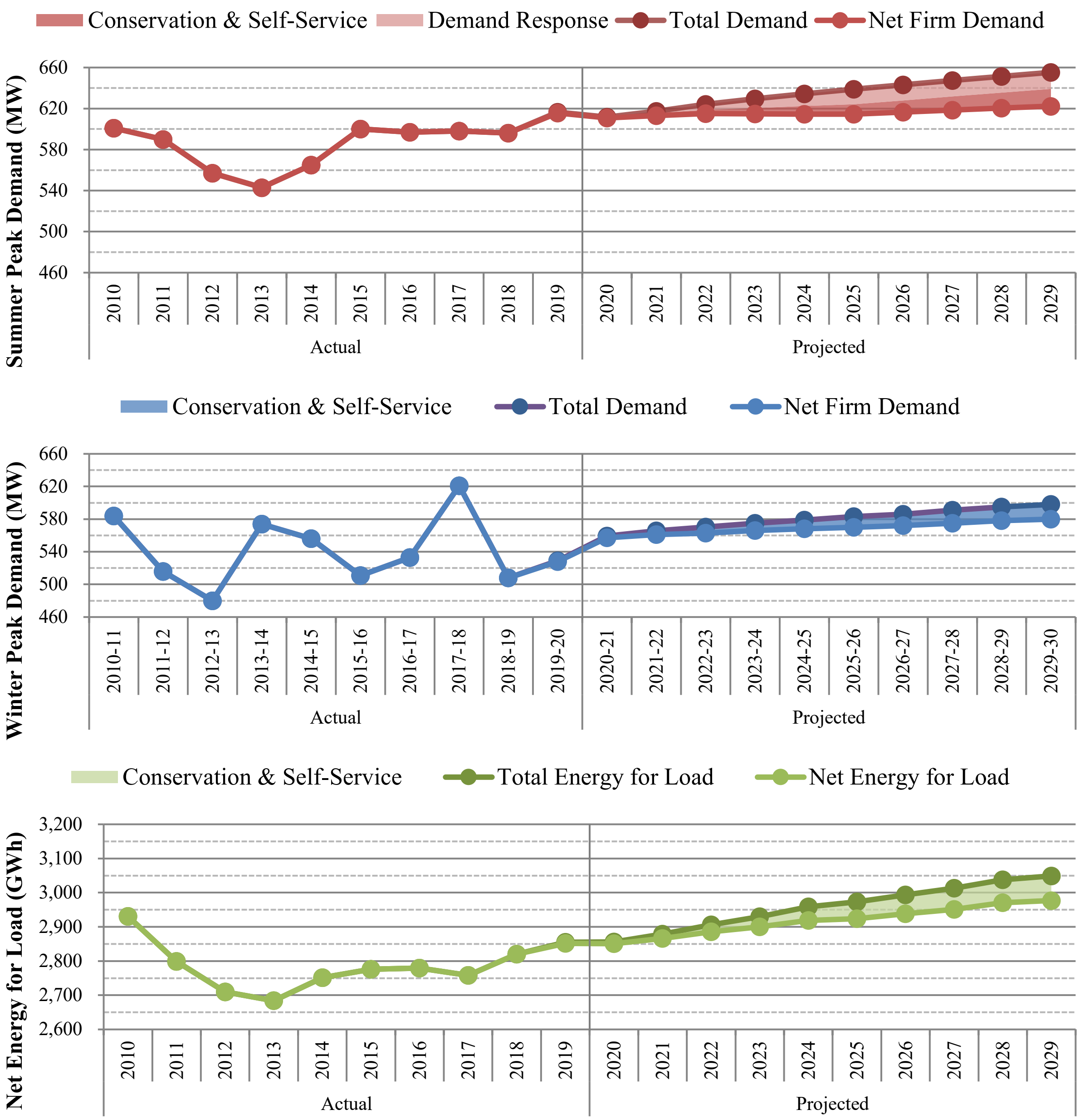
Figure 46: TAL Growth



Source: 2020 Ten-Year Site Plan

The three graphs in Figure 47 shows TAL's seasonal peak demand and net energy for load for the historic years of 2010 through 2019 and forecast years 2020 through 2029. 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 47: TAL Demand and Energy Forecasts



Source: 2020 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 28 shows TAL's actual net energy for load by fuel type as of 2019 and the projected fuel mix for 2029. 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 28: TAL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2019		2029	
	GWh	%	GWh	%
Natural Gas	2,900	**101.6%**	2,998	**100.7%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	48	**1.7%**	117	**3.9%**
Interchange	-95	**-3.3%**	-137	**-4.6%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,853**		**2,978**	

Source: 2020 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 48 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 48: TAL Reserve Margin Forecast

Source: 2020 Ten-Year Site Plan

Generation Resources

Table 29 shows TAL's plan to add a cumulative 36 MW of natural gas-fired reciprocating engines over the 2020-2029 planning period. The utility does not plan any unit retirements.

Table 29: TAL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
New Units			
2020	Hopkins 5	NG – IC	18
2028	Unsited 1	NG – IC	18
Total New Units			**36**
Net Additions			**36**

Source: 2020 Ten-Year Site Plan