REVIEW OF THE

2019 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

NOVEMBER 2019

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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 include input assumptions such as demographics, financial parameters, generating unit operating characteristics, fuel costs, etc. 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 or Plan) 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 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 utility summarizes 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 2019 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

[1]Investor-owned utilities filing 2019 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 2019 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 2019 Ten-Year Site Plan.

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.

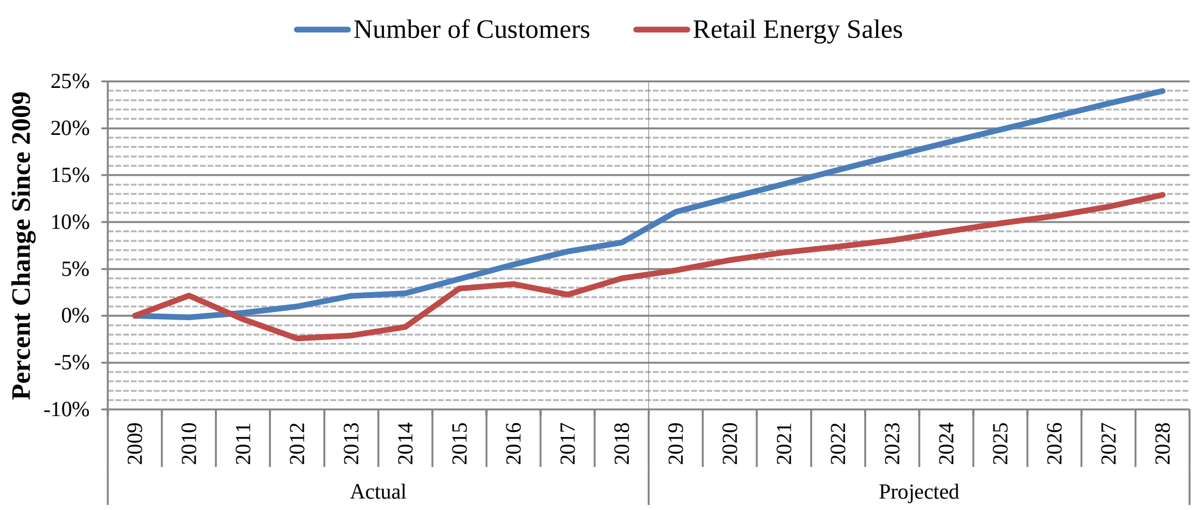
Review of the 2019 Ten-Year Site Plans

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

Load Forecasting

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

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



Source: FRCC 2019 Regional Load and Resource Plan

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

Renewable Generation

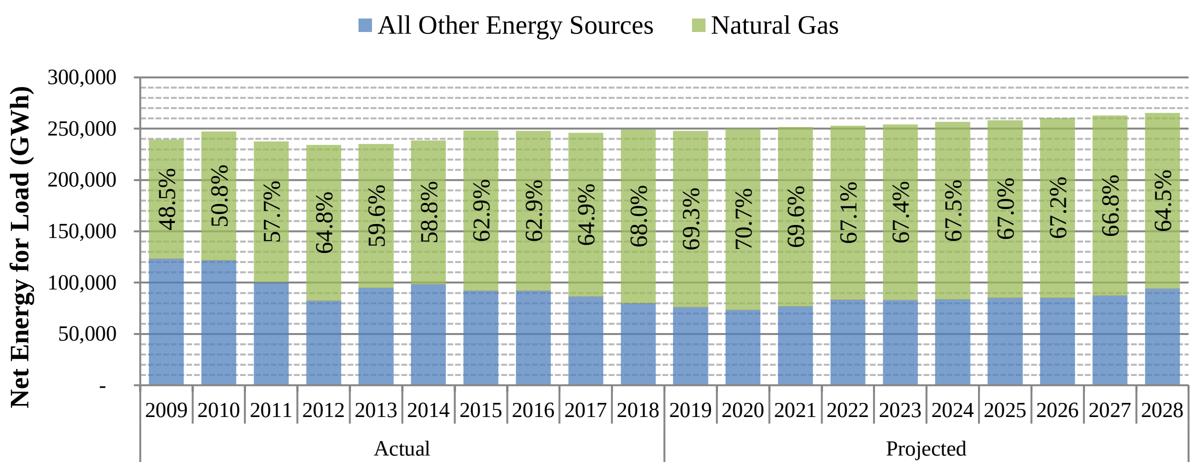
Renewable resources continue to expand in Florida, with approximately 3,335 MW of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar, biomass, and municipal solid waste. These make up approximately 78 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, wind, landfill gas, and hydroelectric. Notably, Florida electric customers had installed 317 MW of demand-side renewable capacity at the end of 2018, resulting in an increase of 55 percent from 2017.

Florida's total renewable resources are expected to increase by an estimated 10,704 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. 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 6,987 MW of utility-owned traditional generation over the planning horizon. This figure represents an increase from the previous year's planned net increase of 3,794 MW. Natural gas consumption is expected to remain somewhat steady and the dominant fuel over the planning horizon, with usage in 2018 at approximately 68 percent of the state's net energy for load (NEL). Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida.

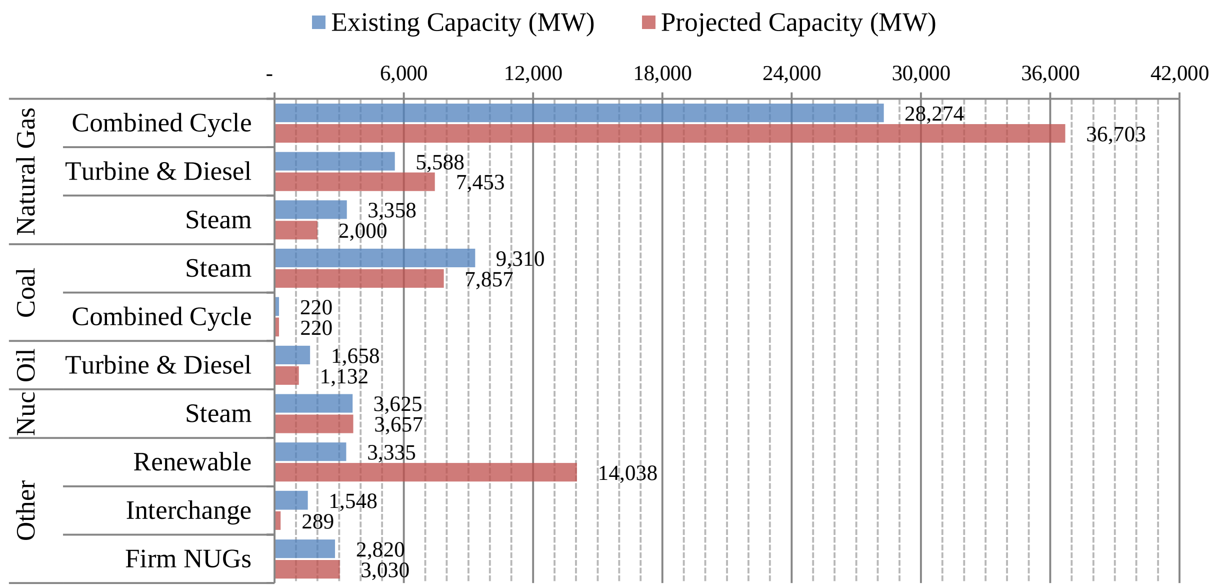
Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



Source: FRCC 2010-2019 Regional Load and Resource Plan

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2019 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 2019 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. Table 1 displays those planned generation facilities that have not yet received a determination of need from the Commission. A petition for a determination of need is generally anticipated four years in advance of the in-service date for a natural gas-fired combined cycle unit.

Table 1: State of Florida - Planned Units Requiring a Determination of Need

Year	Utility Name	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)
2024	GPC	Combined Cycle 2	NG – CC	595
2026	FPL	Unsited CC Facility	NG – CC	1,886
			Total	**2,481**

Source: 2019 Ten-Year Site Plans

Future Concerns

Florida’s electric utilities must also consider environmental concerns associated with existing generators and planned generation to meet Florida’s electric needs. Developments in U.S. Environmental Protection Agency (EPA) resolutions 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 2019 Ten-Year Site Plans 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 2019 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 Plans are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

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

Statutory Authority

Section 186.801, F.S., requires all major generating electric utilities submit a Ten-Year Site Plan to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each 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

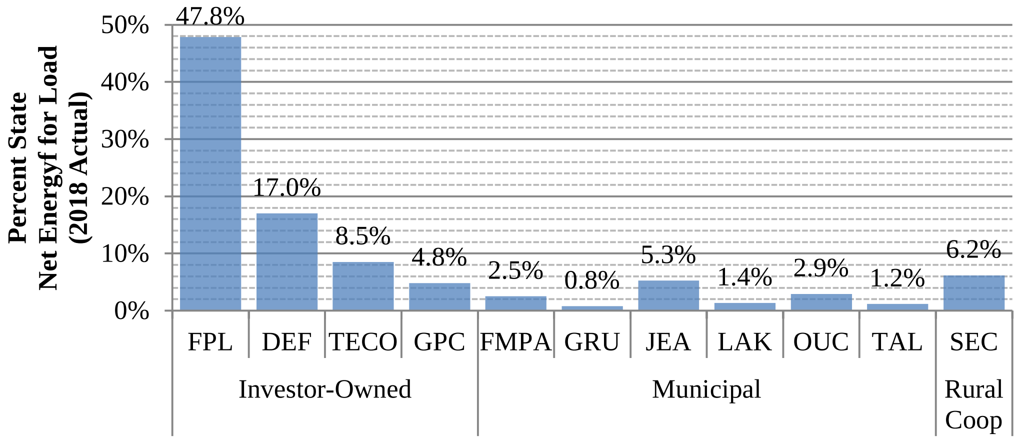
Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file a Ten-Year Site Plan with the Commission every year.

In 2019, 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 2019 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 2018. 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: 2019 Ten-Year Site Plans & FRCC 2019 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. In addition, the FRCC publishes an annual Reliability Report which is also relied upon by the Commission. For certain comparisons, additional data from various government agencies is relied upon, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

Commission staff held a public workshop on October 3, 2019, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2019 Regional Load and Resource Plan and other related matters, including fuel supply reliability and the reliability considerations of utility solar generation additions.

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' 2019 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

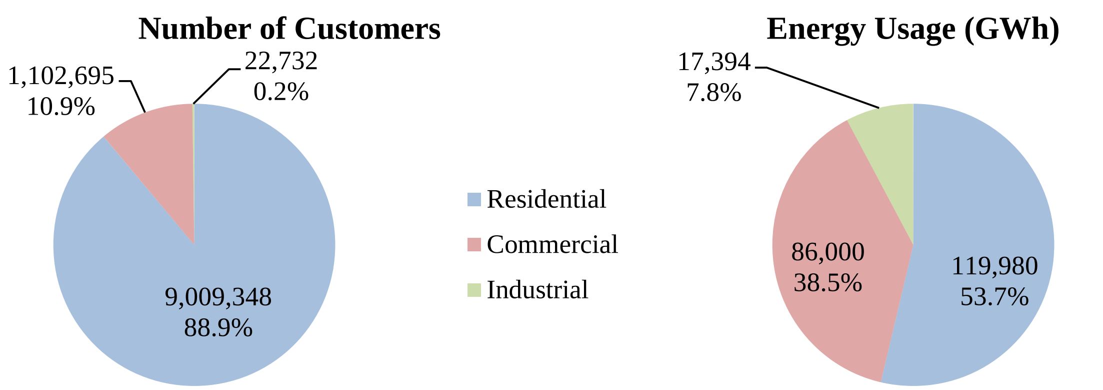
Load Forecasting

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, 2019, residential customers account for 88.9 percent of the total, followed by commercial (10.9 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5. Commercial and industrial customers make up a sizeable percentage of energy sales, due to their higher energy usage per customer.

Figure 5: State of Florida - Electric Customer Composition in 2018



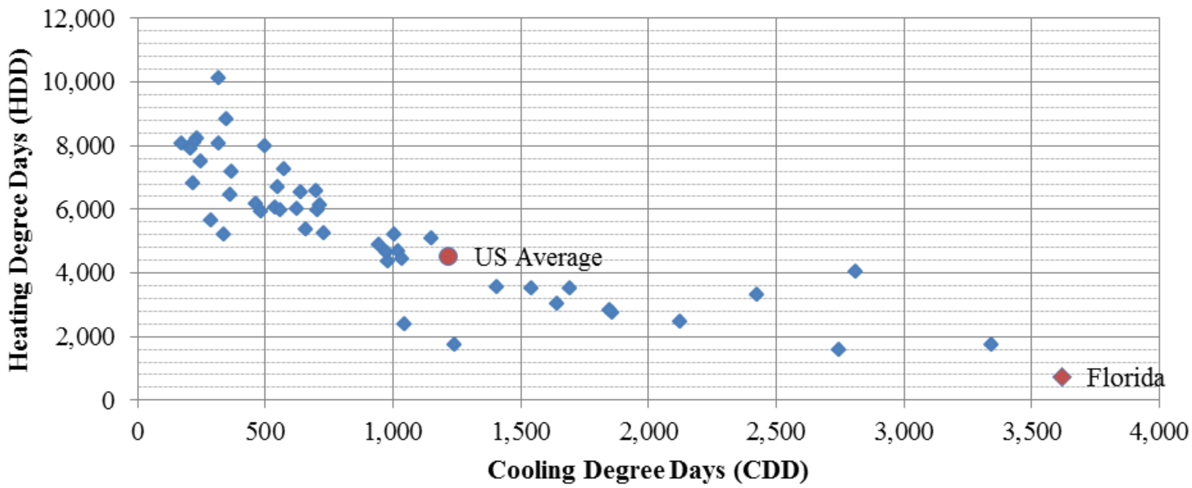
Source: FRCC 2019 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 53.7 percent of retail energy sales in 2018, compared to a national average of 38.5 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 2019 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)

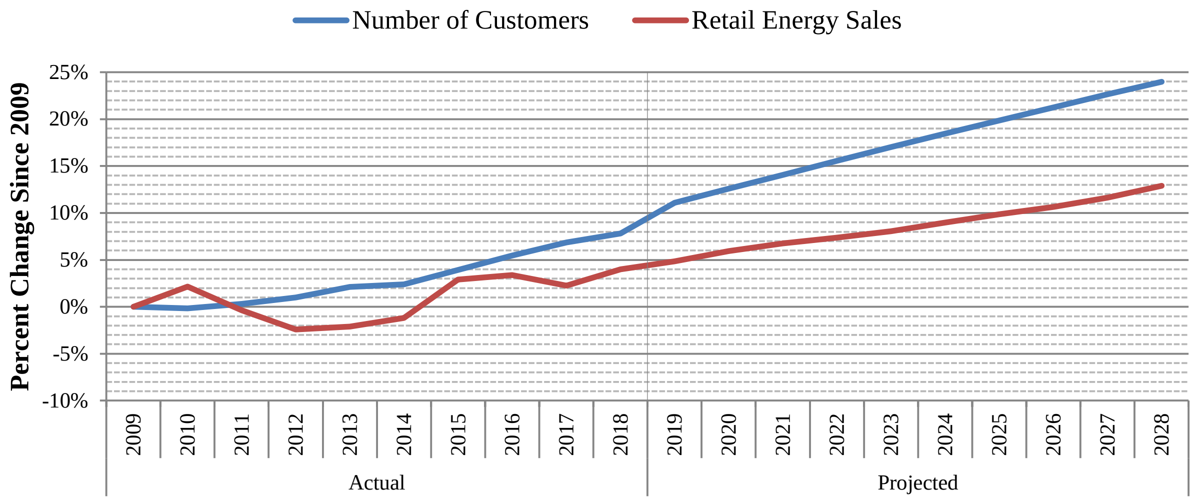


Source: National Oceanic and Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next 10-year period, Florida's retail energy sales are projected to grow at 0.83 percent per year, compared to the 0.43 percent actual annual increase experienced during the 2009-2018 period. The number of Florida's energy customers is anticipated to grow at an average annual rate of about 1.23 percent for the next 10-year period. These trends are shown in Figure 7.

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



Source: FRCC 2019 Regional Load and Resource Plan

The projected retail energy sales trend reflects the product of the utilities' forecasted use-per-customer and forecasted number of customers. 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 key factor affecting utilities' number of customers is population growth. Thus, the projected growth rate of retail energy sales are impacted by the underlying key factors.

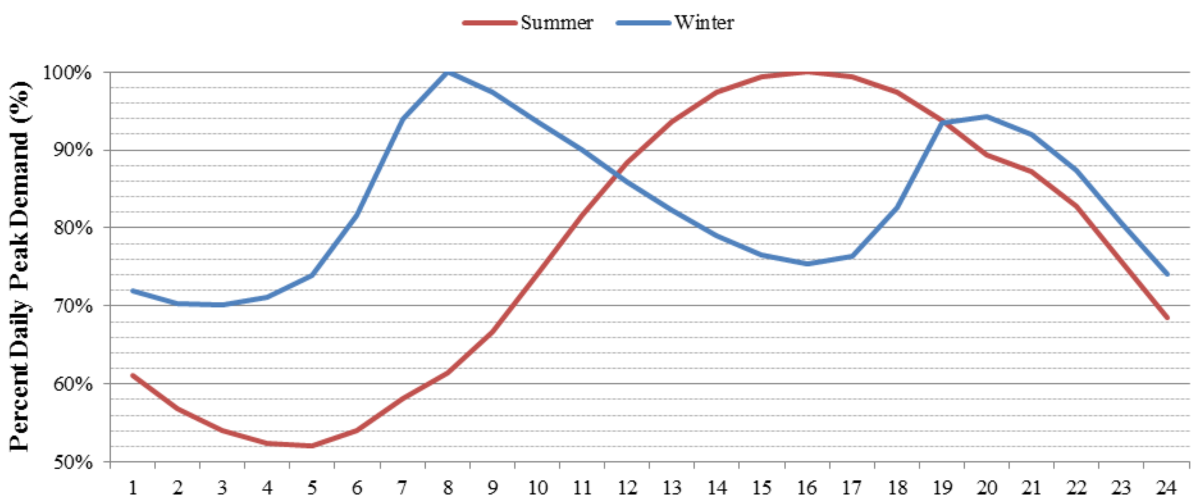
Figure 7 also shows that the projected growth rate in retail energy sales is lower than the projected growth rate in customers, and the difference between these two series is expected to increase throughout the forecast period. Most of the utilities projected a downward trend in use-per-customer. These utilities indicated that the major drivers of this trend are continuous improvements in energy efficiency and customer conservation. Energy efficiency gains cited include a wide variety of appliance efficiency level enhancements, improved building shell and insulation levels in new construction, Wi-Fi thermostat technology, customer-owned solar, more multi-family housing construction compared to single-family housing construction, and alternative energy resources. Customer conservation gains are related to behavioral changes resulting from the 2008 economic downturn, education, and recommendations and incentives associated with the utility-sponsored demand-side management programs.

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.

A primary factor in this is seasonal weather patterns, 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

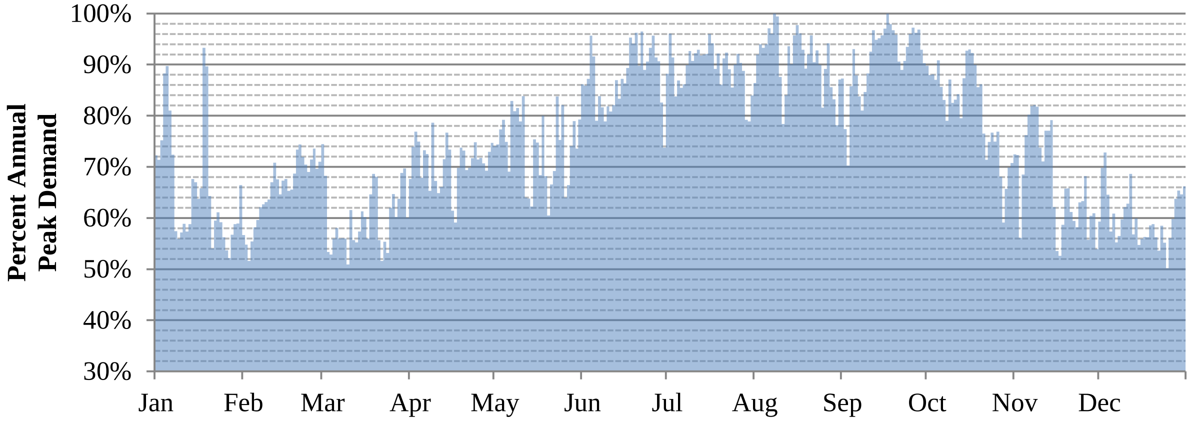


Source: TYSP Utilities' Data Responses

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 2018 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. 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 (2018 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, which can be considered analogous to home air conditioning systems in terms of system demand. The reporting electric utilities estimate approximately 37,449 electric plug-in vehicles were operating in Florida at the end of 2018. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 6, 2019, at 16.8 million vehicles, resulting in an approximate 0.22 percent penetration rate of electric vehicles.[4]

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 506,495 electric vehicles operating within the electric service territories by the end of 2028.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory

YEAR	FPL	DEF	TECO	GULF	GRU	JEA	TAL	TOTAL
2018	22,848	7,468	3,666	559	300	1,229	1,379	**37,449**
2019	30,409	11,149	4,758	630	330	1,601	1,392	**50,269**
2020	40,252	16,080	5,896	698	363	2,029	1,406	**66,724**
2021	53,059	22,669	7,081	761	399	2,507	1,420	**87,896**

[4]Florida Department of Highway Safety and Motor Vehicles January 2019 Vehicle and Vessel Reports and Statistics.

2022	69,803	31,506	8,309	833	439	3,037	1,435	**115,361**
2023	91,594	42,591	9,582	917	483	3,622	1,449	**150,238**
2024	119,979	54,478	11,057	1,000	531	4,262	1,463	**192,770**
2025	156,857	69,019	13,155	1,135	584	4,956	1,478	**247,184**
2026	204,738	86,038	15,638	1,298	642	5,707	1,493	**315,554**
2027	266,883	104,722	18,605	1,505	706	6,517	1,508	**400,447**
2028	347,655	125,363	22,033	1,752	777	7,390	1,524	**506,495**

Source: TYSP Utilities' Data Responses

Table 3 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2028. The anticipated growth would result in an annual energy consumption of 1,861.3 GWh by 2028. Current estimates represent a less than 1 percent impact on net energy for load by 2028.

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

YEAR	FPL	DEF	TECO	GULF	GRU	JEA	TAL*	TOTAL
2018	-	-	27.0	1.9	1.0	-	-	**29.9**
2019	25.9	5.7	37.1	2.1	1.1	6.7	-	**78.6**
2020	62.1	20.8	45.9	2.3	1.2	8.6	-	**140.9**
2021	109.5	40.9	55.1	2.4	1.3	10.7	-	**219.9**
2022	174.4	68.0	64.6	2.6	1.4	13.0	-	**324.1**
2023	259.8	103.5	74.5	2.8	1.5	15.7	-	**457.8**
2024	372.7	145.6	85.9	3.0	1.7	18.6	-	**627.4**
2025	518.8	193.3	102.1	3.4	1.9	21.8	-	**841.1**
2026	706.5	251.3	121.2	3.9	2.1	25.2	-	**1,110.1**
2027	946.9	317.2	144.0	4.5	2.3	29.0	-	**1,443.9**
2028	1,258.9	391.1	170.4	5.4	2.5	33.1	-	**1,861.3**

Source: TYSP Utilities' Data Responses
*City of Tallahassee Utilities did not provide estimates of electric vehicle annual energy consumption.

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

In order to investigate potential unknowns associated with the electric vehicle energy market in Florida, several utilities have initiated Commission-approved 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 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 the 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 2018 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 December 2014, establishing goals for the period 2015 through 2024. During 2015, the Commission reviewed the FEECA Utilities' proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The FEECA Utilities are petitioning the Commission in the current FEECA goal-setting proceeding to approve annual conservation goals for the period 2020 through 2029. The Commission will review DSM Plans that address these goals in 2020, following FEECA goal-setting. All FEECA Utilities that filed a TYSP except FPL incorporated in their planning the impacts of the DSM goals established during the 2014 FEECA goal-setting proceeding. FPL instead based its planning on its proposed DSM goals in the current FEECA proceeding. It is anticipated that all FEECA Utilities will adjust their planning to incorporate the 2020-2029 DSM goals once established by the Commission.

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, 2018, demand response available for reduction of peak load is 2,951 MW for summer peak and 2,887 MW for winter peak. Demand response is anticipated to increase to approximately 3,488 MW for summer peak and 3,321 MW for winter peak by the end of the planning period in 2028.

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 2019, energy efficiency is responsible for peak load reductions of 4,454 MW for summer peak and 3,968 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,169 MW for summer peak and 4,622 MW for winter peak by the end of the planning period in 2028.

Forecast Load & Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated in Figure 10. It should be noted, that 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.

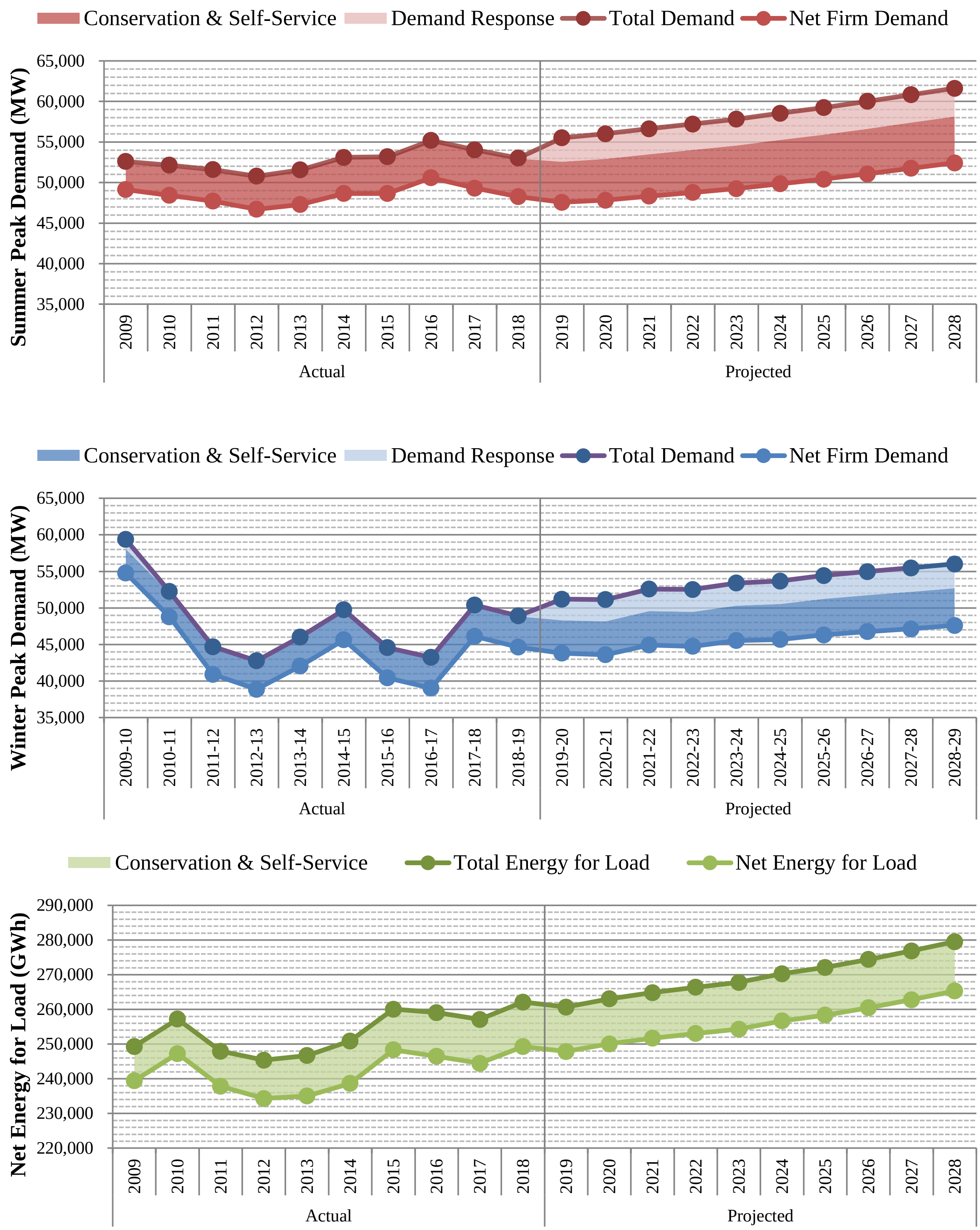
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact 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. The primary exception to this trend was the winter of 2009-2010, when a larger portion of the available demand response resources were called upon.

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 two 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 winter 2009-2010 peak during the planning period.

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



Source: FRCC 2019 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. End use models are used to capture trends in appliance and equipment saturation and efficiency, as well as building size and thermal efficiency, on residential and commercial 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 review methodology, previously used by the Commission, involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2018 retail energy sales were compared to the forecasts made in 2013, 2014, and 2015. These differences, expressed as percentage error rates, are used to determine each utility's historic forecast accuracy using 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 2019 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2014 through 2018 to forecasts made between 2009 and 2015. As discussed previously, the period before the 2007 recession 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 forecast errors (the difference between the actual data and the forecasts made five years prior) were increasing with time starting in 2012 due to the unexpected impact of the recession and its impact on retail energy sales in Florida. However, the forecast errors have started to return to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the actual sales data provided in the 2017 Ten-Year Site Plans. The forecasting error rates (five-year rolling average and/or absolute average) derived from 2018 and 2019 Ten-Year Site Plans show continued decreases.

Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts[5]
(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%

Source: 2002-2019 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-year period used in the analysis in Table 4.

[5]During the course of review of the 2019 Ten-Year Site Plans, certain utilities amended the actual data of their Retail Energy Sales that was reported in previous TYSPs in responses to staff-issued data requests. Consequently, the calculated error rates of utilities' historical forecast have been changed in comparison with what staff presented in the "Review of the 2018 Ten-Year Site Plans."

As displayed in Table 5 the utilities' retail energy sales forecasts show a consistent positive error rate beginning in 2007. 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 four years' one-year ahead forecasts and the last years' two-year ahead forecast all bear negative error rates (under-forecasts), with the current TYSPs showing a very small error rate.

Table 5: TYSP Utilities – Accuracy of Retail Energy Sales Forecasts – Annual Analysis[6]
(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		
2007	0.57%	2.26%	3.49%	3.59%	4.20%	3.05%	3.11%	3.11%
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%	1.75%

Source: 2002-2019 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2018 in Table 5 than the significantly higher error rates shown in earlier years associated with the recession. 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.

[6]During the course of review of the 2019 Ten-Year Site Plans, certain utilities amended the actual data of their Retail Energy Sales that was reported in previous TYSPs in responses to staff-issued data requests. Consequently, the calculated error rates of utilities' historical forecast have been changed in comparison with what staff presented in the "Review of the 2018 Ten-Year Site Plans."

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 3,335 MW of firm and non-firm generation capacity, which represents 5.5 percent of Florida's overall generation capacity of 60,703 MW in 2018. 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	1743	52.3%
Biomass	469	14.1%
Municipal Solid Waste	374	11.2%
Waste Heat	310	9.3%
Wind*	272	8.2%
Landfill Gas	116	3.5%
Hydroelectric	51	1.5%
Renewable Total	**3,335**	**100.00%**

Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses
*Gulf's wind resources are not present in-state.

Of the total 3,335 MW of renewable generation, approximately 1,202 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 609 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 55 percent of Florida's existing renewable generation capacity comes from non-utility generators, of which municipal solid waste, biomass, and waste heat 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 a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output 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 year end 2018, approximately 317 MW of renewable capacity from nearly 38,000 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 31 installations and 7.1 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

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

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018
Number of Installations	2,833	3,994	5,302	6,697	8,581	11,626	15,994	24,166	37,862
Installed Capacity (MW)	19.9	28.4	42.2	63.0	79.8	107.5	141	205	317

Source: Annual Utility Reports

Utility-Owned Renewable Generation

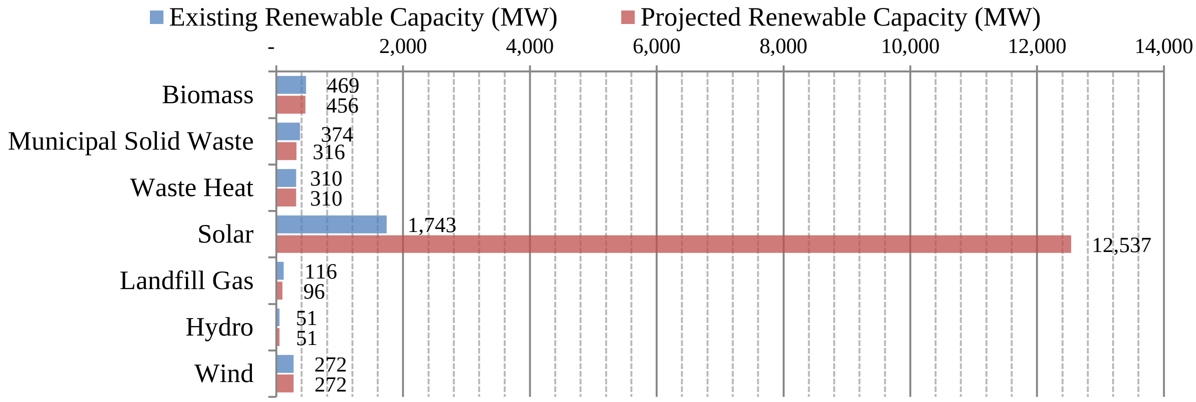
Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, 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 1,195 MW of existing utility-owned solar capacity, approximately 601 MW, or about 50 percent, is considered firm.

GPC has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not actually be delivered to GPC's system, the renewable attributes for their output are retained by GPC for the benefit of its customers.

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 10,704 MW over the 10-year planning period, a significant increase from last year's estimated 7,049 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[7]



Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the 10,704 MW projected net increase in renewable capacity, firm resources contribute 4,005 MW, or about 37 percent, of the total. Solar generation alone contributes an incremental 4,096 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 10,795 MW to be installed. This consists of 9,049 MW of utility-owned solar and 1,746 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 1,200 MW, 700 MW, and 600 MW, respectively. The Commission has already approved 894 MW of FPL's SoBRA capacity, 344 MW of DEF's SoBRA capacity, and 405 MW of TECO's SoBRA capacity. FPL, DEF, and TECO are also

[7]JEA's and Gulf's wind resources are not present in-state.
[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.*

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 utility-scale (greater than 10 MW) solar capacity generation planned within the next 10 years.

Table 8: TYSP Utilities - Planned Solar Installations

Year	Utility	Type	Capacity (MW)
2019	FPL	Utility Owned	301
	DEF	Utility Owned	120
	TECO	Utility Owned	278
	TAL	Purchased	40
		2019 Subtotal	**739**
2020	FPL	Utility Owned	745
	DEF	Combined	374
	TECO	Utility Owned	149
	FMPA	Purchased	149
	JEA	Purchased	50
	OUC	Purchased	112
		2020 Subtotal	**1,579**
2021	FPL	Utility Owned	450
	DEF	Combined	355
	TECO	Utility Owned	53
	JEA	Purchased	200
		2021 Subtotal	**1,057**
2022	FPL	Utility Owned	900
	DEF	Combined	300
	SEC	Purchased	40
		2022 Subtotal	**1,240**
2023	FPL	Utility Owned	900
	DEF	Combined	225
		2023 Subtotal	**1,125**
2024	FPL	Utility Owned	750
	DEF	Combined	225
		2024 Subtotal	**975**
2025	FPL	Utility Owned	1,050
	DEF	Combined	225
		2025 Subtotal	**1,275**
2026	DEF	Combined	150
		2026 Subtotal	**150**
2027	FPL	Utility Owned	900
	DEF	Combined	150
		2027 Subtotal	**1,050**
2028	FPL	Utility Owned	1,200
	DEF	Combined	150
		2028 Subtotal	**1,350**
TBD	DEF	Purchased	250
		TBD Subtotal	**250**
		Total Installations	**10,790**

Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Renewable Outlook

Florida's renewable generation is projected to increase over the planning period. A significant portion of this increase can be attributed to growth in solar PV generation. As a result of the operational characteristics of these installations, namely the coincidence of solar generation and summer peak demand, some utilities are reporting a fraction of the nameplate capacity of these installations as firm resources for reliability considerations.

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]

In the 2019 Ten-Year Site Plans, firm storage capacity is being proposed for inclusion in resource planning for the first time. All of the proposed capacity consists of Li-ion battery storage, totaling over 500 MW.

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. 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.

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 is installing a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility will be interconnected with the solar array and will add 5.6 MW of

[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.*

firm capacity. The expected project benefits include firming of the solar output during peak times and contribution to contingency reserves. TECO will continue to analyze storage technology and its applications with the objective to integrate these resources into their portfolio.

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.

Traditional Generation

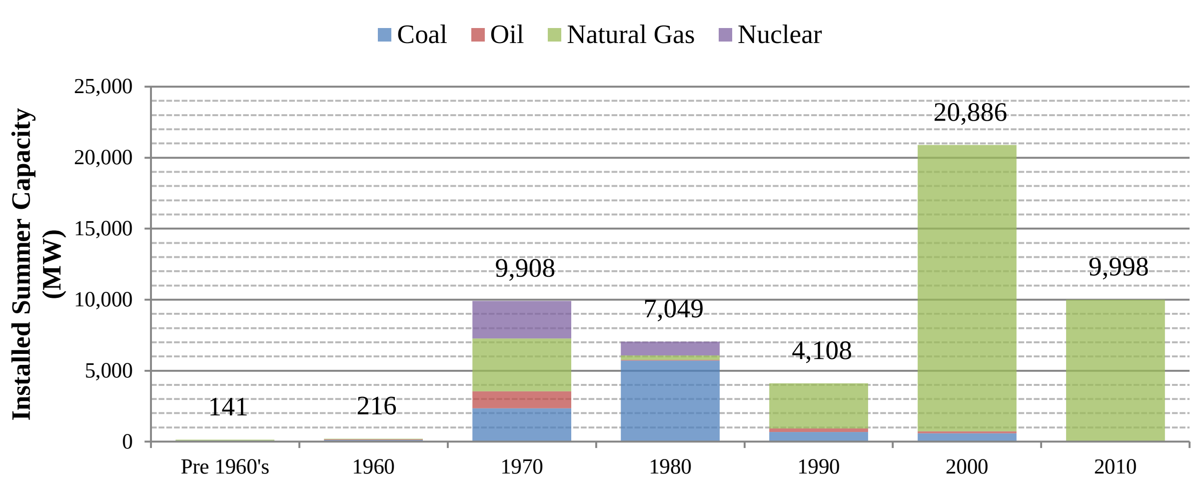
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. 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 22 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 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 2019 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 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. No final actions have been taken. These recent regulatory 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 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.

- 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.

- 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 new landfills in which coal ash is deposited.

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 3,567 MW of existing generation that is scheduled to be retired during the planning period. 13 natural gas units totaling 1,871 MW, 4 coal units totaling 1,169 MW, and 12 oil units totaling 527 MW are set to retire within the next 10 years. Notably, TECO plans to retire its coal-fired Big Bend Unit 2 in 2021 and convert its coal-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
	DEF	Higgins P1 – P4	NG – CT	107
			2020 Subtotal	**155**
2021	FPL	Manatee 1 & 2	NG – ST	1,618
	TECO	Big Bend 2	BIT – ST	385
			2021 Subtotal	**2,003**
2022	GRU	Deerhaven FS01	NG – ST	75
			2022 Subtotal	**75**
2023	SEC	Seminole Generating Station 1 or 2*	BIT – ST	634
			2023 Subtotal	**634**
2024	GPC	Crist 4	BIT – ST	75
			2024 Subtotal	**75**
2025	DEF	Bayboro P1 – P4	DFO – CT	172
	GPC	Pea Ridge 1 - 3	NG – CT	12
			2025 Subtotal	**184**
2026	GRU	Deerhaven GT01 & GT02	NG – CT	35
	GPC	Crist 5	BIT – ST	75
			2026 Subtotal	**110**
2027	DEF	Debary P2 – P6	DFO – CT	249
	DEF	Bartow P1 & P3	DFO – CT	82
			2027 Subtotal	**331**
			Total Retirements	**3,567**
* SEC has not determined whether to retire SGS 1 (626 MW) or SGS 2 (634 MW) at this time.				

Source: 2019 Ten-Year Site Plans

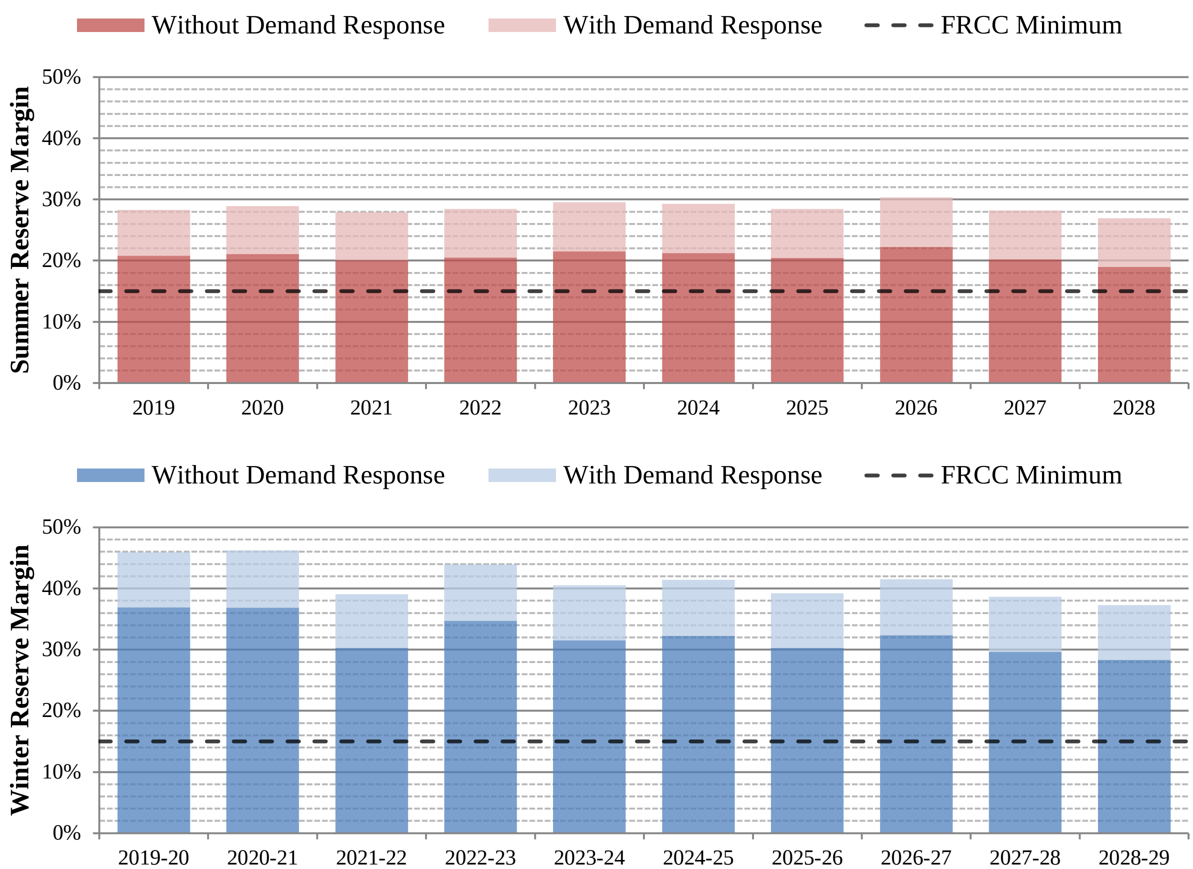
Reliability Requirements

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 2019 Regional Load and Resource Plan

Role of Demand Response in Reserve Margin

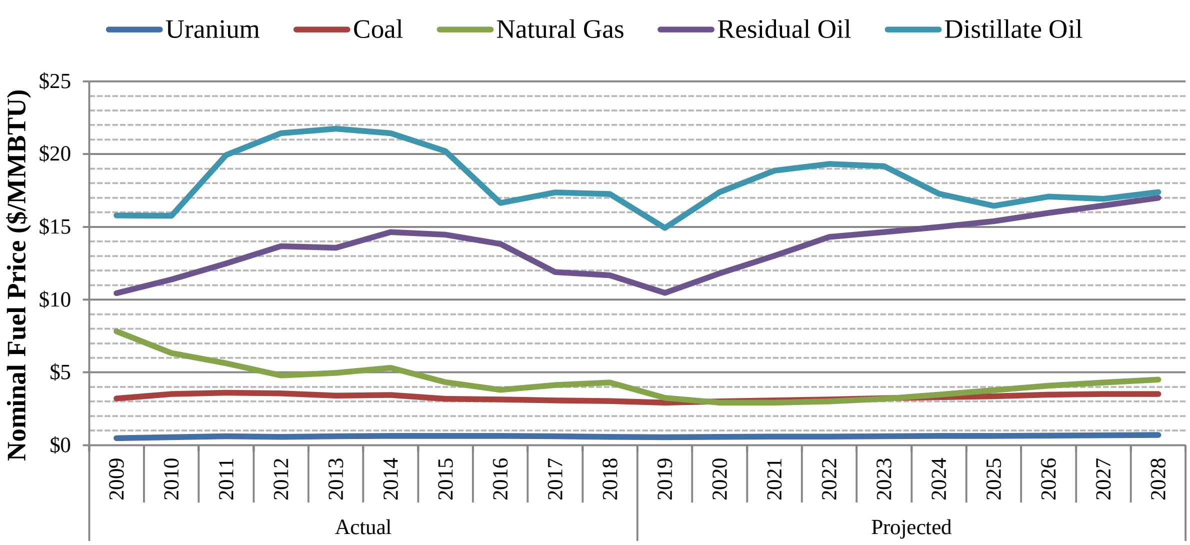
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.9 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 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 also factor into Florida utilities' fuel mix, albeit minimally compared to historical levels. Figure 14 below illustrates the weighted average fuel price history and forecasts for the reporting electric utilities. Fuel oil remains the most expensive fuel and suitable for backup and peaking purposes only.

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



Source: Utilities Responses to FPSC Staff Data Requests – 2019 TYSP Review

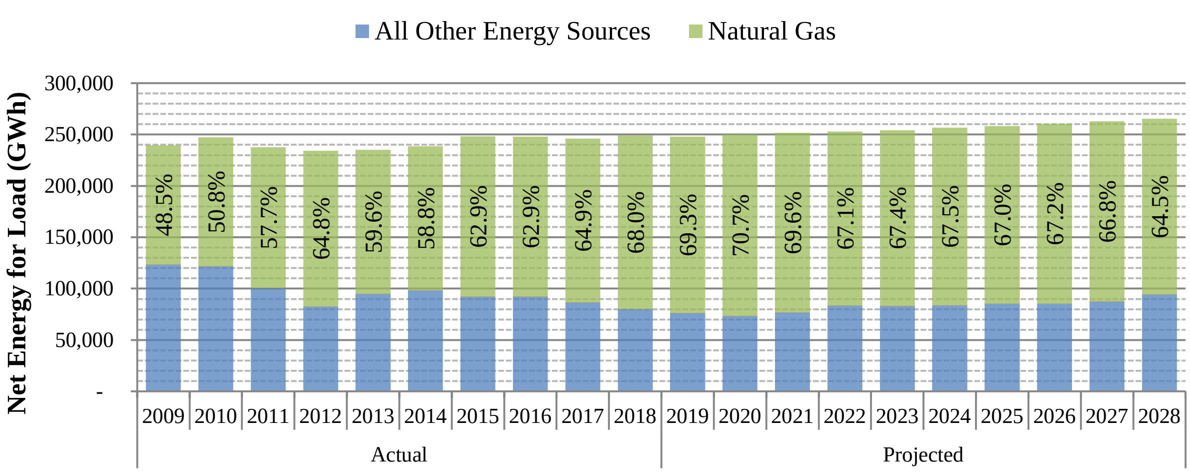
From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This led to concerns regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units 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 above, 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 within the last 10 years, displacing coal, 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 2018. Natural gas consumption is anticipated to remain somewhat steady throughout the remainder of the planning period.

Figure 15: State of Florida - Natural Gas Contribution to Energy Consumption

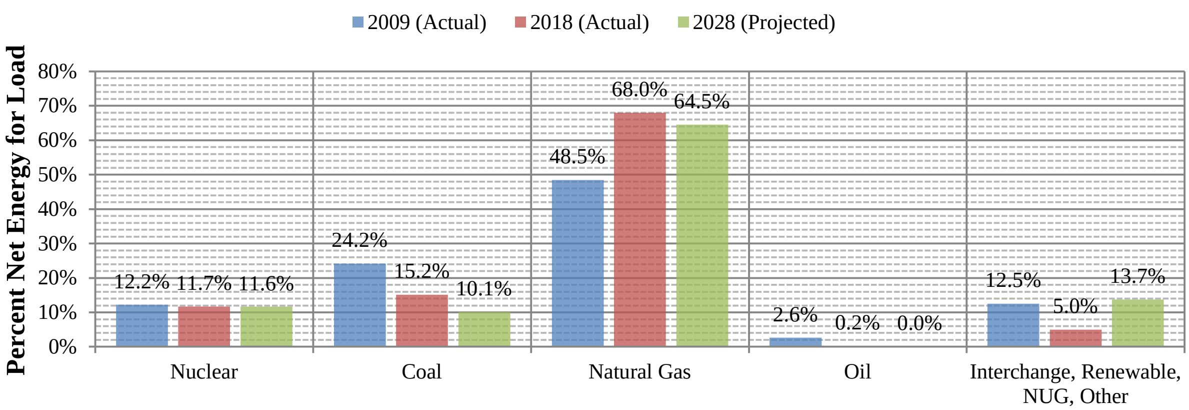


Source: FRCC 2010-2019 Regional Load and Resource Plan

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 2009 and 2018, and forecast year 2028. 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 Fuel Consumption



Source: FRCC 2010-2019 Regional Load and Resource Plan

Based on 2017 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.[14] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Florida's percentage of natural gas consumption for 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.

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

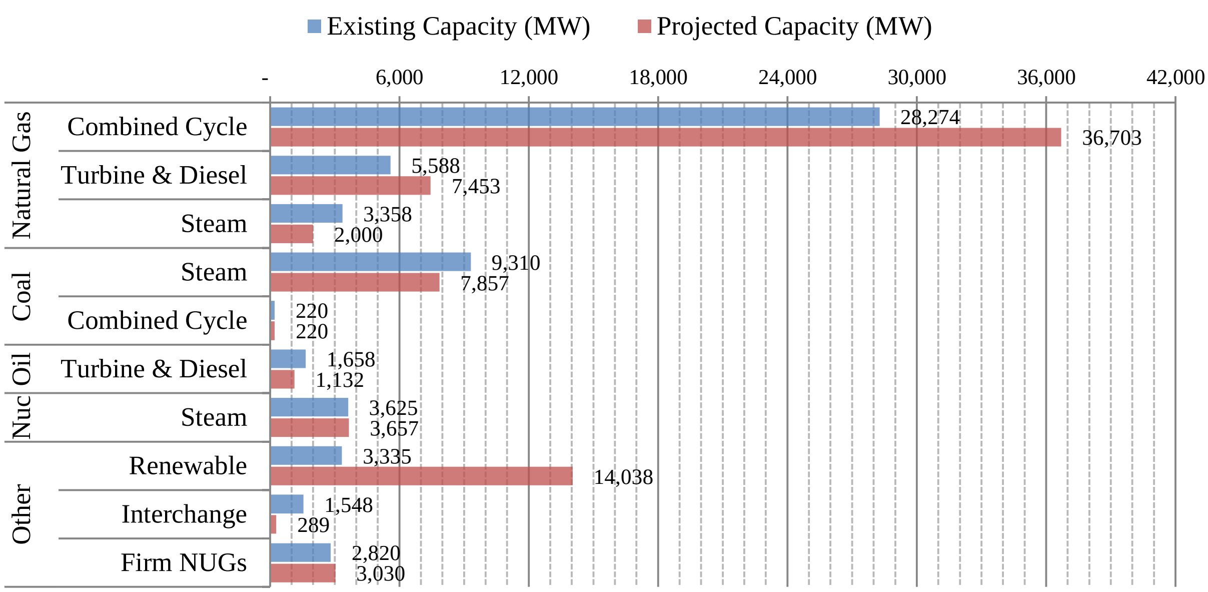
New Generation Planned

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.

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' 2019 Ten-Year Site Plans and the FRCC's 2019 Regional Load and Resource Plan.

Figure 17: State of Florida - Current and Projected Installed Capacity by Fuel



Source: FRCC 2019 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

Excluding renewables and minor nuclear and coal generation uprates, all remaining new power plants are natural gas-fired combustion turbines, internal combustion units, or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. 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 8,291 MW of proposed new natural gas-fired generation included in the 2019 Ten-Year Site Plans.

Table 10: State of Florida - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW)	Notes
Previously Approved New Units				
2019	FPL	Okeechobee Energy Center	1,778	Docket No. 20150196-EI
2022	FPL	Dania Beach Energy Center	1,163	Docket No. 20170225-EI
2022	SEC	Seminole CC Facility	1,108	Docket No. 20170266-EI
			Subtotal	**4,049**
New Units Requiring PPSA Approval				
2024	GPC	Combined Cycle 2	595	
2026	FPL	Unsited CC Facility	1,886	
			Subtotal	**2,481**
New Units Not Requiring PPSA Approval				
2019	TAL	Hopkins 1-4	74	
2020	LAK	C.D. McIntosh 2	115	
2021	TEC	Big Bend 5 & 6	660	Convert to CC in 2023
2023	TEC	Future CT 1	229	
2025	TAL	Hopkins 5	18	
2026	TEC	Future CT 2	229	
2027	DEF	Unknown 1 & 2	436	
			Subtotal	**1,761**
			Total Planned Natural Gas Capacity	**8,291**

Source: 2019 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. As shown in Table 10, there is approximately 2,481 MW of generation that would require certification under the PPSA. Based on the unit type and projected in-service date, GPC may be filing a need determination sometime in 2020 and FPL may be filing a need determination sometime in 2022.

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 2019 Ten-Year Site Plans and the FRCC 2019 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	150	500	05/28/1988	04/20/1990	06/01/2019
TECO	Thonotosassa Wheeler	8	230	06/21/2007	08/07/2008	TBD
TECO	Wheeler to Willow Oak	17	230	06/21/2007	08/07/2008	TBD

Source: 2019 Ten-Year Site Plans & FRCC 2019 Regional Load and Resource Plan

Utility Perspectives

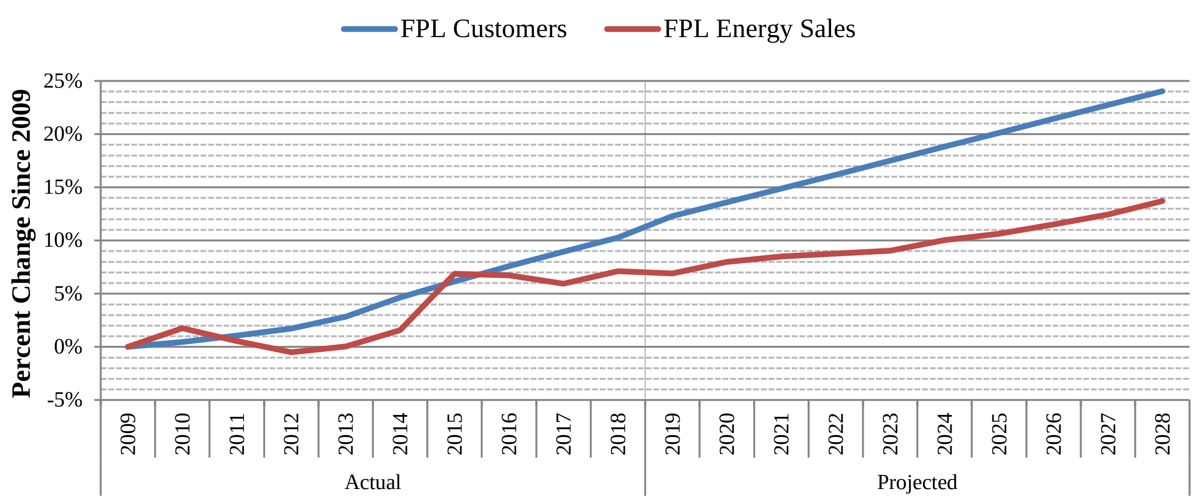
Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. The Utility's service territory is within the FRCC region and is primarily in south Florida and along the east coast. As an investor-owned utility, the Commission has regulatory authority over all aspects of FPL's operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2019 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2018, FPL had approximately 4,961,330 customers and annual retail energy sales of 110,053 GWh or approximately 47.8 percent of Florida's annual retail energy sales. Figure 18 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the past 10 years, FPL's customer base has increased by 10.27 percent, while retail sales have grown by 7.10 percent. As illustrated, FPL's retail energy sales are anticipated to exceed its historic 2015 peak in 2019.

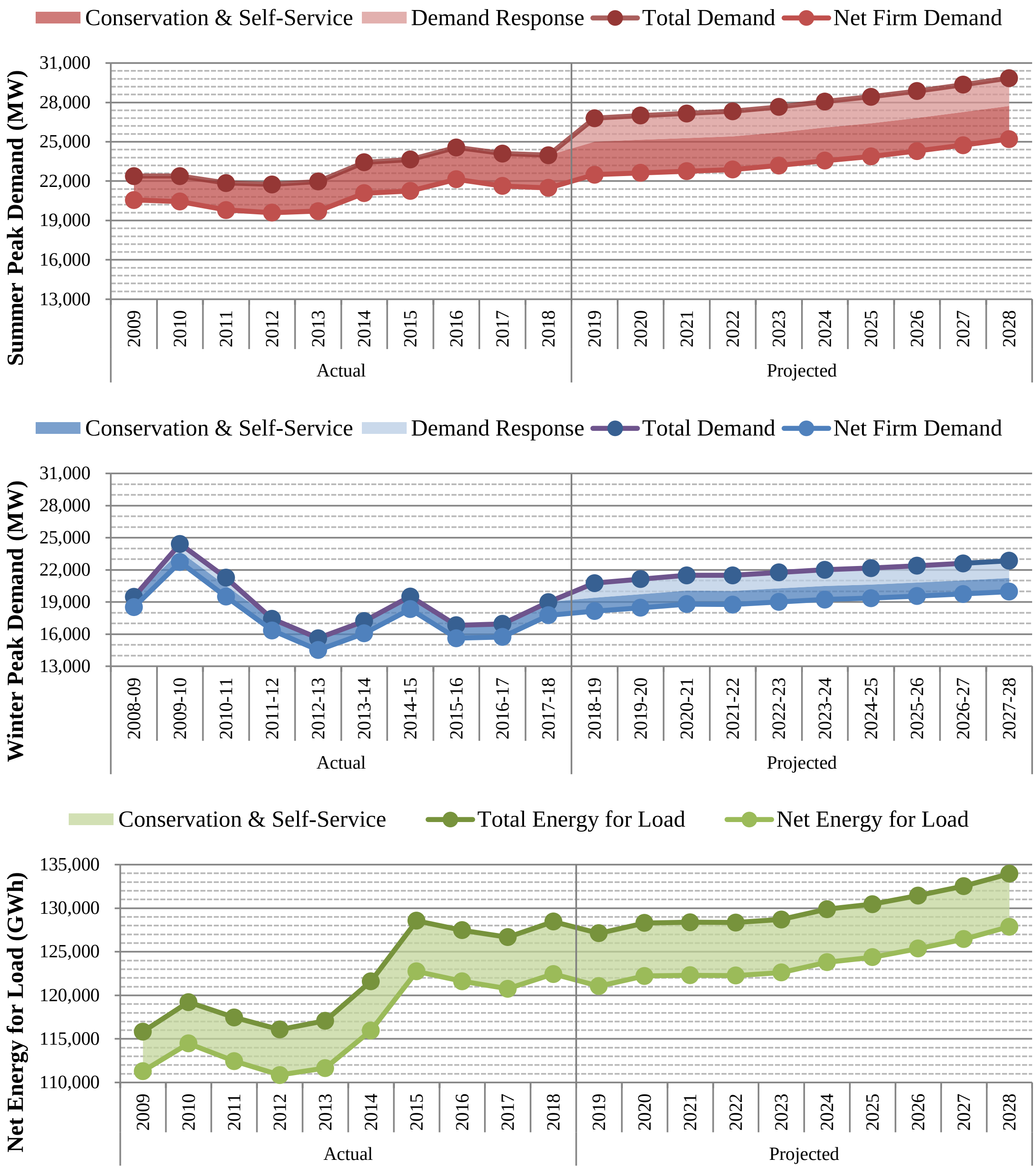
Figure 18: FPL Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 19 show FPL's seasonal peak demand and net energy for load, for the historic years 2009 through 2018 and forecast years 2019 through 2028. 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. Historically, demand response has not been activated during the seasonal peak demand, excluding the winters of 2009-10 and 2010-11. As an investor-owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. FPL is currently petitioning the Commission for approval of annual conservation goals for the period 2020 through 2029. The Utility's 2019 Ten-Year Site Plan reflects these proposed goals.

Figure 19: FPL Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2018, and the projected fuel mix for 2028. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 98 percent of net energy for load. FPL plans that renewable energy will provide over 14 percent of its generation by 2028. FPL is projected to have the second highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

Table 12: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	91,213	**74.5%**	76,202	**59.6%**
Coal	2,586	**2.1%**	1,819	**1.4%**
Nuclear	28,176	**23.0%**	29,675	**23.2%**
Oil	377	**0.3%**	5	**0.0%**
Renewable	1,887	**1.5%**	18,609	**14.5%**
Interchange	0	**0.0%**	0	**0.0%**
Other	-1,793	**-1.5%**	1,631	**1.3%**
Total	**122,447**		**127,941**	

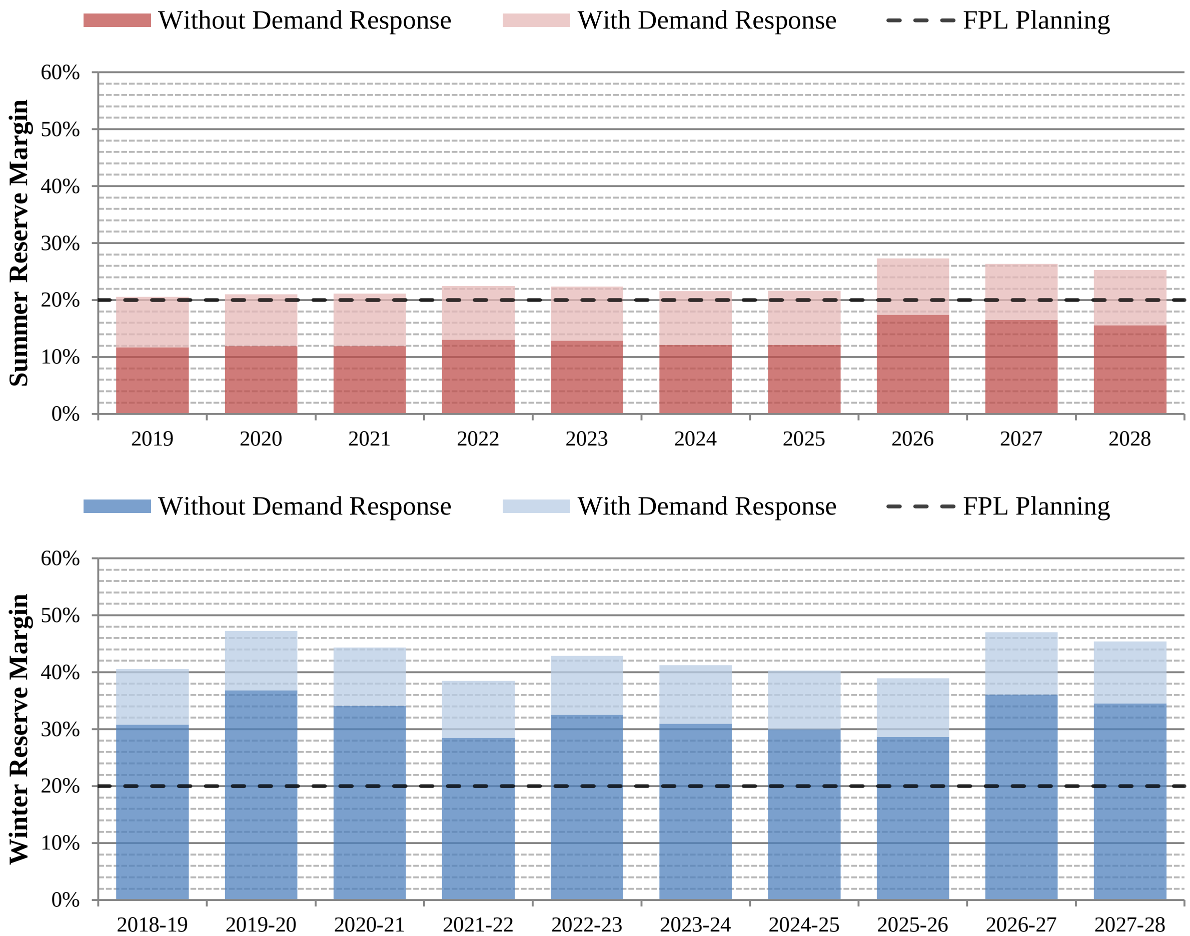
Source: 2019 Ten-Year Site Plan

Reliability Requirements

While previously only reserve margin has been discussed, Florida's utilities use multiple indices to determine the reliability of the 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 planning reserve margin criterion. Figure 20 displays the forecast planning reserve margin for 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 20: FPL Reserve Margin Forecast



Source: 2019 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.

Generation Resources

FPL plans two unit retirements and multiple unit additions during the planning period, as described in Table 13. FPL plans to retire Manatee Units 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. As FPL's generation system becomes more fuel-efficient, these units' already low capacity factors (approximately 11% in 2018) are projected to trend even lower in the coming years. 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.

The projected in-service dates of FPL's planned nuclear units are outside the 10-year planning period. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Clean Energy Center, a natural gas-fired combined cycle unit, which was granted on January 19, 2016.[15] The unit is expected to go into service in 2019. FPL filed another need determination with the Commission on October 20, 2017, this time for the Dania Beach Clean Energy Center, another natural gas-fired combined cycle unit, which was granted on March 19, 2018.[16] The unit is expected to be in-service by 2022.

FPL has included 7,152 MW of planned solar additions outside of the 894 MW of SoBRA additions approved in the Fuel and Purchased Power Cost Recovery Clause docket.[17,18] Another

[15]Order No. PSC-16-0032-FOF-EI, issued January 19, 2016, in Docket No. 20150196-EI, *In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company.*
[16]Order No. PSC-2018-0150-FOF-EI, issued March 19, 2018, in Docket No. 20170225-EI, *In re: Petition for determination of need for Dania Beach Clean Energy Center Unit 7, by Florida Power & Light Company.*
[17]Order No. PSC-2018-0028-FOF-EI, issued January 8, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*
[18]Order No. PSC-2018-0610-FOF-EI, issued December 26, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

298 MW of SoBRA additions are the subject of an active Commission docket.[19] The in-service dates of 447 MW and the construction of another 596 MW of non-SoBRA solar additions are dependent on the outcome of another active Commission docket regarding FPL's SolarTogether Program.[20] FPL plans to conduct further economic analysis before reaching a decision to proceed with these additions. All planned solar additions make up approximately 59 percent of FPL's planned future units.

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. 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.

[19]Document No. 01342-2019, issued March 1, 2019, in Docket No. 20190001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*
[20]Document No. 03066-2019, issued March 13, 2019, in Docket No. 20190061-EI, *In re: Petition for approval of FPL SolarTogether program and tariff, by Florida Power & Light Company.*

Table 13: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2021	Manatee 1 & 2	NG – ST	1,618	N/A	
Total Retirements			**1,618**		
New Units					
2019	Interstate Solar Energy Center	PV	75	41	These SoBRA units received Commission approval in Docket No. 20180001-EI.
2019	Miami-Dade Solar	PV	75	41	
2019	Pioneer Trail Solar Energy Center	PV	75	41	
2019	Sunshine Gateway Solar	PV	75	41	
2019	Okeechobee Clean Energy Center	NG – CC	1,778	N/A	Docket No. 20150196-EI.
2020	Hibiscus	PV	75	41	These SoBRA units are the subject of an active Commission docket, 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	These non-SoBRA units are the subject of an active Commission docket, 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	
2021	Egret	PV	75	41	
2021	Lakeside	PV	75	41	
2021	Magnolia Springs	PV	75	41	
2021	Pelican	PV	75	41	
2021	Rodeo	PV	75	41	
2021	Discovery	PV	75	41	
2021	Manatee County Site	PV	75	37	
2021	Nassau	PV	75	37	
2021	Orange Blossom	PV	75	37	
2021	Palm Bay	PV	75	37	
2021	Putnam County Site	PV	75	37	
2021	Sabal Palm	PV	75	37	
2021	Trailside	PV	75	37	
2021	Union Springs	PV	75	37	
2021/22	Battery Storage	BAT	469	N/A	
2022	Dania Beach Clean Energy Center	NG – CC	1,163	N/A	Docket No. 20170225-EI
2022-28	Unsited Solar	PV	5,662	2,158	
2026	Unsited Combined Cycle	NG – CC	1,886	N/A	
Total New Units			**13,044**	**3,275**	
Percentage of Solar Units Planned of Total New Units			**59%**		
Net Additions			**11,426**		

Source: 2019 Ten-Year Site Plan

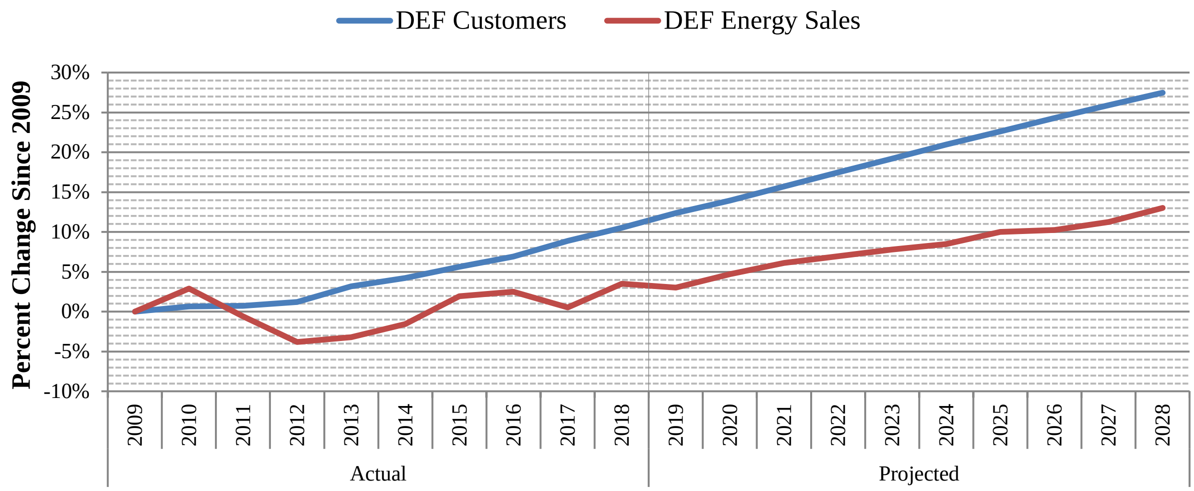
Duke Energy Florida, LLC (DEF)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, DEF had approximately 1,801,564 customers and annual retail energy sales of 39,144 GWh or approximately 17.0 percent of Florida's annual retail energy sales. Figure 21 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, DEF's customer base has increased by 10.51 percent, while retail sales have grown by 3.49 percent.

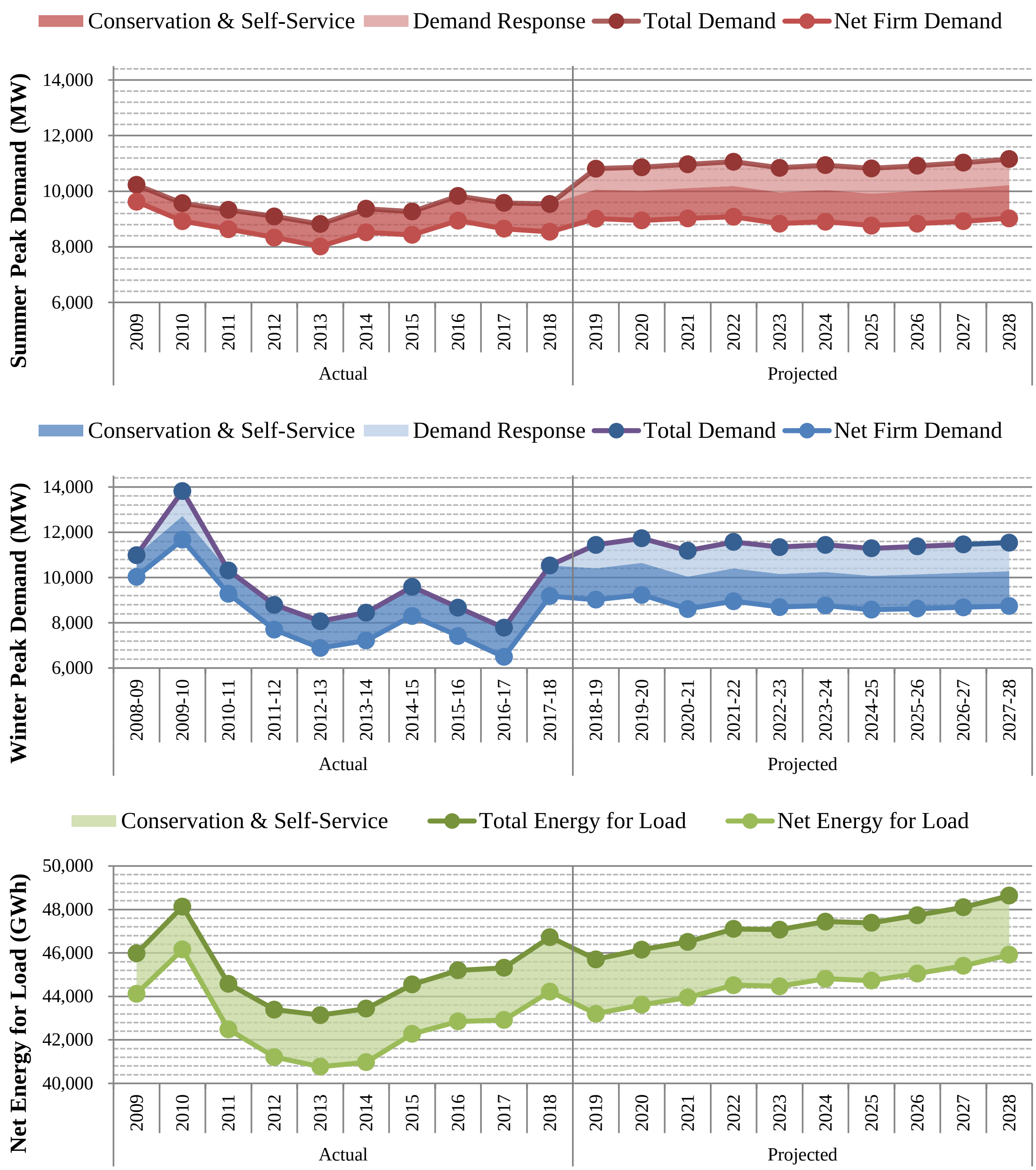
Figure 21: DEF Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 22 show DEF's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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. The Utility's 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Figure 22: DEF Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 84 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 2028. DEF projects the third highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

Table 14: DEF Energy Consumption by Fuel Type

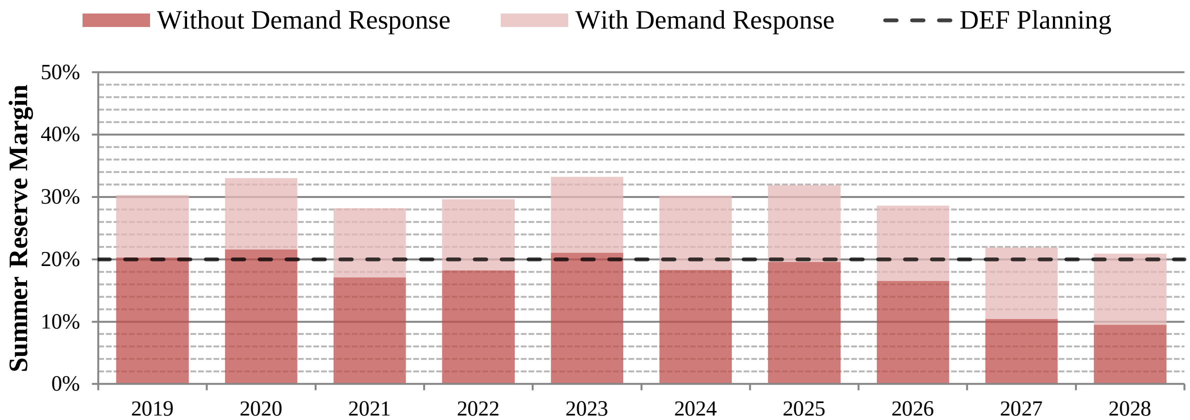
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	28,687	**64.9%**	35,377	**77.0%**
Coal	8,422	**19.0%**	3,930	**8.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	90	**0.2%**	63	**0.1%**
Renewable	1,270	**2.9%**	6,489	**14.1%**
Interchange	2,244	**5.1%**	56	**0.1%**
NUG & Other	3,511	**7.9%**	2	**0.0%**
Total	**44,224**		**45,917**	

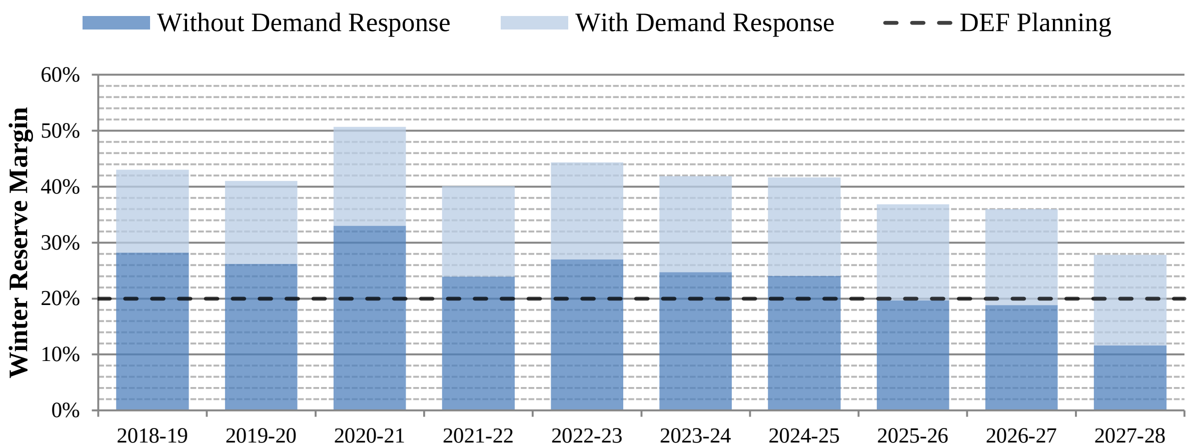
Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 23 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 controlled by its summer peaking throughout the planning period.

Figure 23: DEF Reserve Margin Forecast





Source: 2019 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 15. DEF plans to retire several gas-fired units at multiple power plant sites. DEF's adding two combustion turbines at an undesignated site(s) in 2027.

DEF has included 750 MW of planned solar additions outside of the 344 MW of SoBRA additions approved by the Commission.[21,22] 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 future units.

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

[21]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.*
[22]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.*

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 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2020	Avon Park P1	NG – CT	24	N/A	
2020	Avon Park P2	DFO – CT	24	N/A	
2020	Higgins P1 – P4	NG – CT	107	N/A	
2025	Bayboro P1 – P4	DFO – CT	172	N/A	
2027	Debary P2 – P6	DFO – CT	249	N/A	
2027	Bartow P1 & P3	DFO – CT	82	N/A	
Total Retirements			**658**		
New Units					
2019	St Petersburg Pier	PV	0.4	0.4	
2019	Trenton[1]	PV	75	43	These SoBRA units received Commission approval in Docket No. 20190072-EI.
2019	Lake Placid[1]	PV	45	26	
2020	Debray[1]	PV	75	34	
2020	Columbia[2]	PV	75	43	This SoBRA unit received Commission approval in Docket No. 20180149-EI.
2020	Solar 10 & 11	PV	150	85	
2021	Solar 12 – 14	PV	205	117	
2022	Solar 15 & 16	PV	150	85	
2023	Solar 17	PV	75	43	
2024	Solar 18 & 19	PV	150	85	
2025	Solar 20 & 21	PV	150	85	
2026	Solar 22	PV	75	43	
2027	Unknown 1 & 2	NG – CT	436	N/A	
2027	Solar 23	PV	75	43	
2028	Solar 24	PV	75	43	
Total New Units			**1,811**	**775**	
Percentage of Solar Units Planned of Total New Units			**76%**		
Net Additions			**1,153**		

Source: 2019 Ten-Year Site Plan

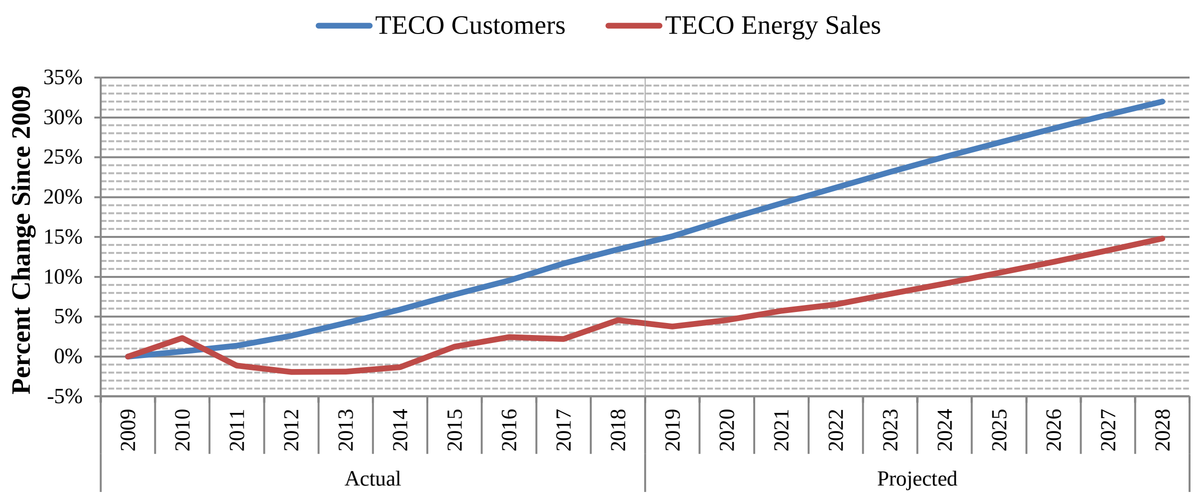
Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, TECO had approximately 756,254 customers and annual retail energy sales of 19,631 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 24 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, TECO's customer base has increased by 13.42 percent, while retail sales have increased by 4.56 percent.

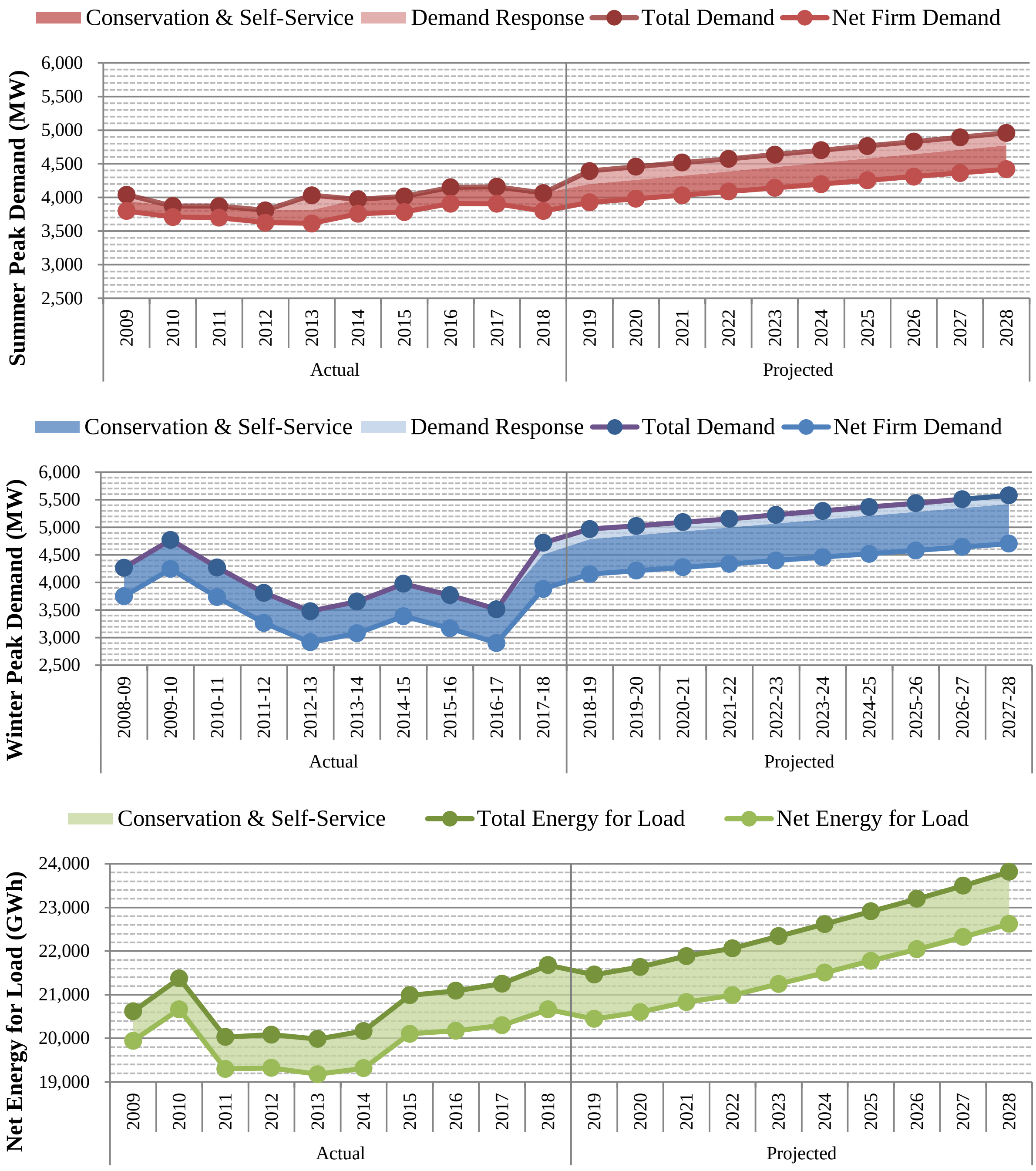
Figure 24: TECO Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 25 show TECO's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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.

Figure 25: TECO Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

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. The Utility's 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. Based on its 2019 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 78 percent of net energy for load. In the future, TECO projects that energy from coal will slightly decrease and energy from natural gas will increase. TECO projects that renewable energy will increase from 0.6 percent to 6.6 percent by 2028. TECO projects the sixth highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

Table 16: TECO Energy Consumption by Fuel Type

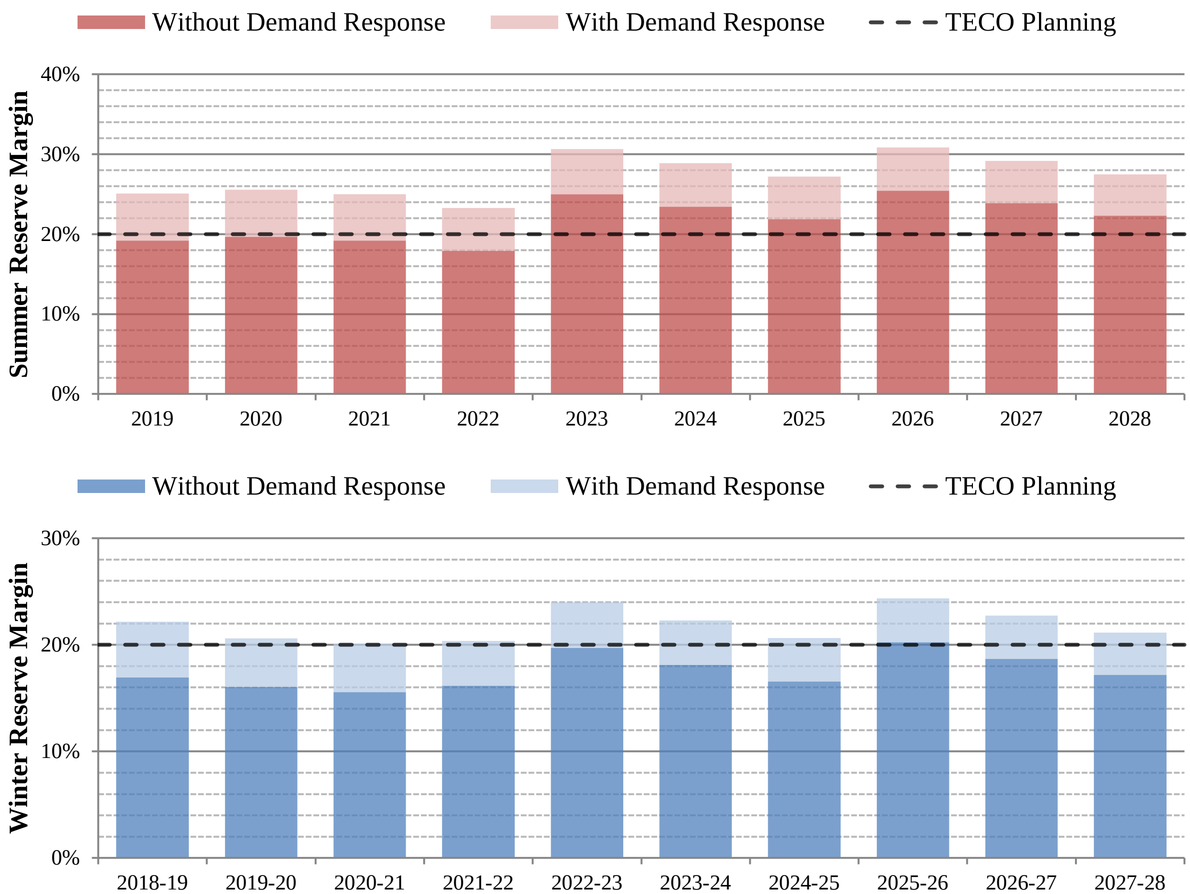
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	16,097	**77.9%**	17,729	**78.4%**
Coal	2,982	**14.4%**	2,836	**12.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	118	**0.6%**	1,491	**6.6%**
Interchange	89	**0.4%**	0	**0.0%**
NUG & Other	1,376	**6.7%**	566	**2.5%**
Total	**20,662**		**22,622**	

Source: 2019 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 26 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 are controlled by its summer peak throughout the planning period. 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 26: TECO Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

TECO plans a unit retirement and multiple unit additions during the planning period, as described in Table 17. TECO anticipates retiring its coal-fired Big Bend Unit 2 in 2021. TECO also plans to convert its coal-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023. The Florida Department of Environmental Protection has determined that a determination of need is not necessary for this conversion. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2023 and 2026, and anticipates increasing the amount of planned solar projects over the planning period.

TECO has included 84.5 MW of planned solar additions outside of its SoBRA units, 405 MW of which are already Commission-approved.[23,24] Another 149 MW of SoBRA additions are the subject of an active Commission docket.[25] All planned solar additions make up approximately 30 percent of TECO's planned future units.

TECO is installing a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility will be interconnected with the solar array and will add 5.6 MW of firm capacity. The expected project benefits include firming of the solar output during peak times and contribution to contingency reserves. TECO will continue to analyze storage technology and its applications with the objective to integrate these resources into our portfolio.

[23]Order No. PSC-2018-0288-FOF-EI, issued June 5, 2018, in Docket No. 20170260-EI, *In re: Petition for limited proceeding to approve first solar base rate adjustment (SoBRA), effective September 1, 2018, by Tampa Electric Company.*

[24]Order No. PSC-2018-0571-FOF-EI, issued December 07, 2018, in Docket No. 20180133-EI, *In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.*

[25]Document No. 05259-2019, filed June 28, 2019, in Docket No. 20190136-EI, *In re: Petition for a limited proceeding to approve third SoBRA, by Tampa Electric Company.*

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2021	Big Bend 2	BIT – ST	385	N/A	
Total Retirements			**385**		
New Units					
2019	Bonnie Mine Solar[1]	PV	38	18	These SoBRA units received Commission approval in Docket No. 20180133-EI. Only 18 MW of the Lake Hancock project where approved.
2019	Grange Hall Solar[1]	PV	61	33	
2019	Lithia Solar[1]	PV	75	39	
2019	Peace Creek Solar[1]	PV	55	31	
2019	Lake Hancock[1]	PV	50	26	
2020	Little Manatee River[2]	PV	75	39	These SoBRA units are the subject of an active Commission docket, Docket No. 20190136-EI.
2020	Wimauma Solar[2]	PV	75	43	
2021	Big Bend 5 & 6	NG – CT	660	N/A	
2021	Mountain View	PV	53	30	
2023	Future CT 1	NG – CT	229	N/A	
2026	Future CT 2	NG – CT	229	N/A	
Total New Units			**1,597**	**259**	
Percentage of Solar Units Planned of Total New Units			**30%**		
Net Additions			**1,212**		

Source: 2019 Ten-Year Site Plan

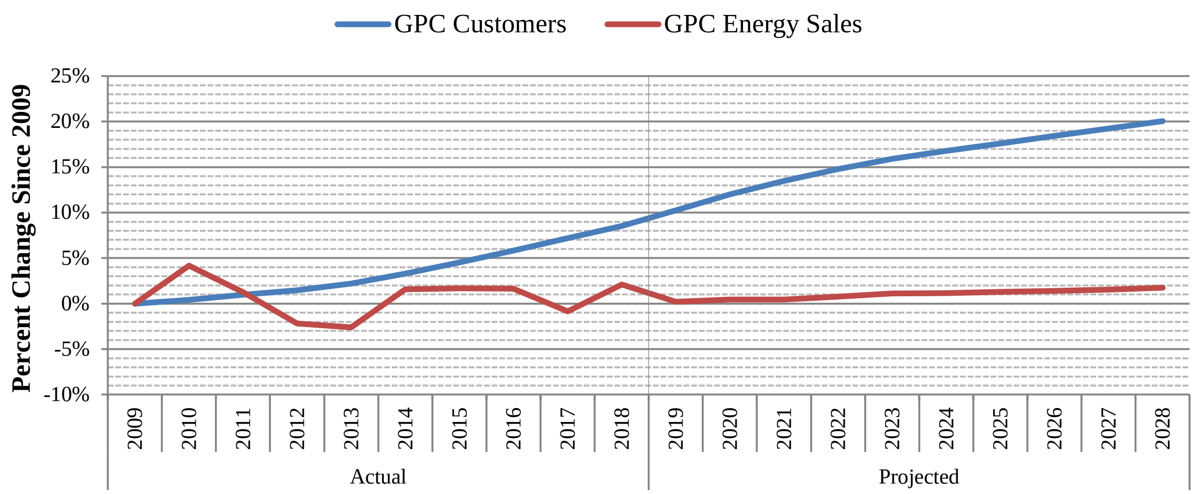
Gulf Power Company (GPC)

GPC is an investor owned utility, and is Florida's sixth largest electric utility. It represents the smallest of the generating investor-owned utilities, and the only one inside the Southern Company electric system. As GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by GPC is consumed within Florida. NextEra Energy Inc., FPL's parent company, has recently acquired GPC through a purchase that closed during the first half of 2019. Starting in 2020, Gulf's planning services will be performed by the resource planning group at FPL, and Gulf's 2020 Ten-Year Site Plan will reflect the results of these analyses. 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 GPC's 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, GPC had approximately 464,682 customers and annual retail energy sales of 11,132 GWh or approximately 4.8 percent of Florida's annual retail energy sales. Figure 27 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, GPC's customer base has increased by 8.52 percent, while retail sales have increased by 2.11 percent. As illustrated, Gulf's retail energy sales are not anticipated to exceed its historic 2010 peak during the planning period.

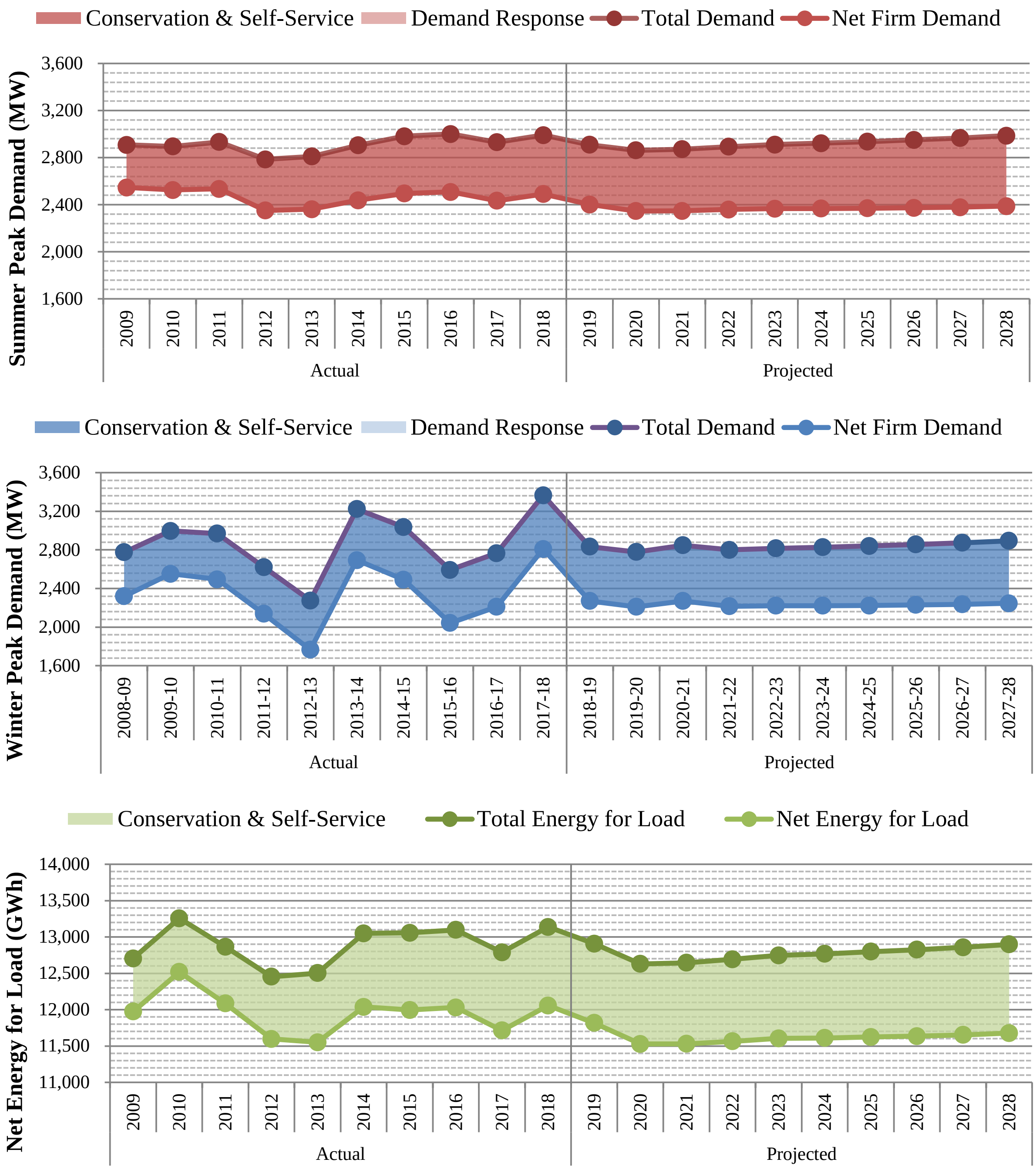
Figure 27: GPC Growth



Source: 2019 Ten-Year Site Plan

As an investor-owned utility, GPC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2019 Ten-Year Site Plan effects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 28 shows GPC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the full impact of demand-side management.

Figure 28: GPC Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 18 shows GPC's actual net energy for load by fuel type as of 2018, and the projected fuel mix for 2028. GPC is an energy exporter, producing approximately 26 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2018, coal was the second most utilized fuel source. By 2028, GPC's 2019 TYSP projects an increase in energy exports of 31 percent of native load. GPC projects energy from coal will increase to approximately 57 percent of system energy by the year 2028, the highest percentage of energy consumption from coal in 2028 of the TYSP Utilities. GPC projects the fourth highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

Table 18: GPC Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	8,150	**67.6%**	7,237	**62.0%**
Coal	5,526	**45.8%**	6,637	**56.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	1,327	**11.0%**	1,273	**10.9%**
Interchange	-3,095	**-25.7%**	-3,624	**-31.0%**
NUG & Other	148	**1.2%**	155	**1.3%**
Total	**12,057**		**11,678**	

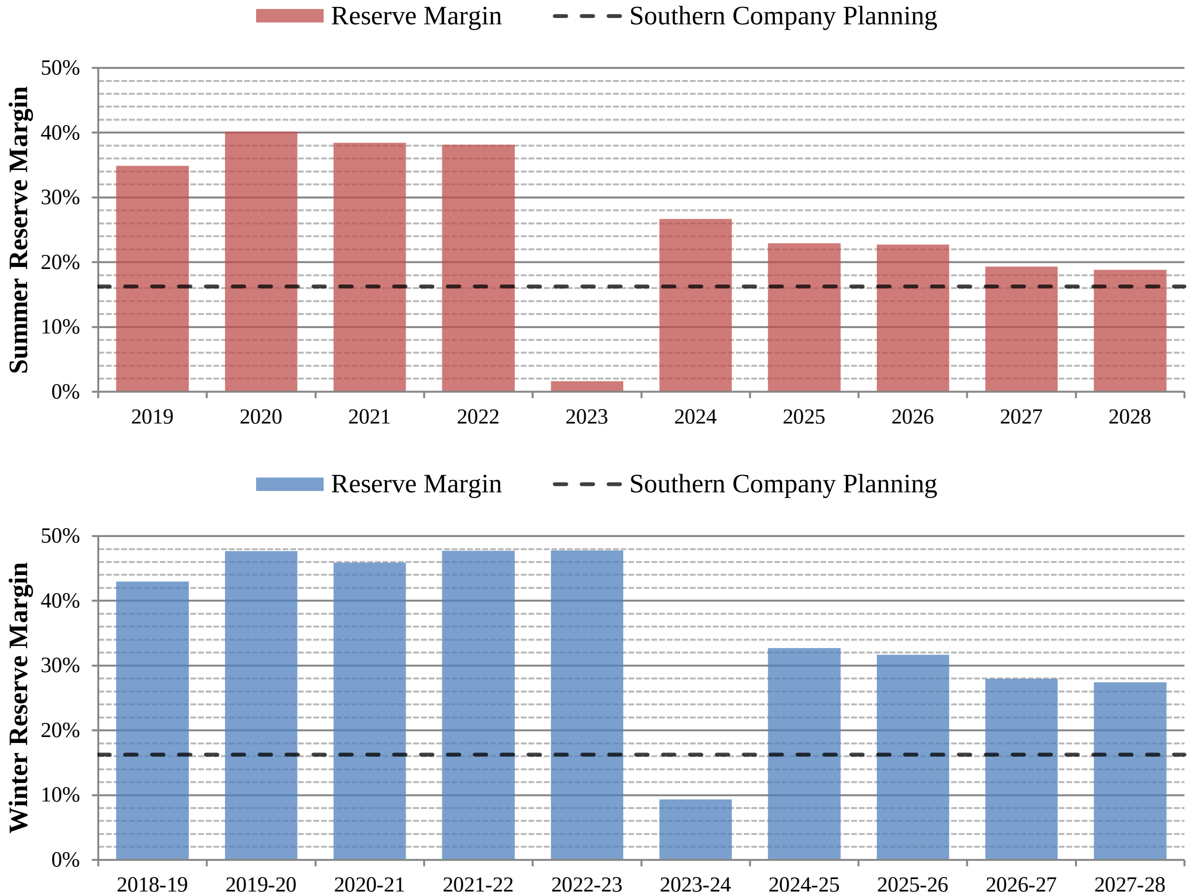
Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

As previously noted, GPC is the only TYSP utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 16.25 percent summer reserve margin for the year 2022 and beyond. Figure 29 displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs.

As shown in Figure 29, GPC is reporting a 1.6 percent reserve margin for summer 2023 and a 9.3 percent reserve margin for winter 2023-24. This is due to the expiration of a purchased power agreement with Shell Energy North America (Shell PPA) for 885 MW of firm capacity in May 2023. GPC currently anticipates replacing a portion of this lost capacity with a 595 MW 1x1 combined cycle unit in June 2024. GPC expects to manage its reserve margin requirements in the interim, between the expiration of the Shell PPA and the in-service date of its anticipated new combined cycle unit, with short-term arrangements that are available through the Intercompany Interchange Contract's reserve sharing mechanism or through capacity purchases from the market. The Intercompany Interchange Contract's reserve sharing mechanism is a benefit afforded to GPC from its association with the Southern electric system. However, while GPC expects that these purchases will serve to meet its reserve margin requirements, it has not included any contributed capacity from the purchases into its reserve margin projections due to their nature as market purchases. The FRCC's reserve margin is projected to be 30 percent in 2023 at the time of summer peak, and is projected to be 41 percent in 2023/24 at the time of winter peak. As shown below, GPC's generation needs are typically determined by its summer peak.

Figure 29: GPC Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

GPC plans a few unit retirements and additions during the planning period, as described in Table 19. Pea Ridge natural gas-fired combustion turbines 1-3 are scheduled to be retired in 2025. GPC has also indicated that the coal-fired units Crist 4 & 5 are tentatively scheduled for retirement in 2024 and 2026, respectively. GPC has indicated these retirement dates borrow from end-of-life depreciation calculations and do not represent results from an operational evaluation of the units.

Based on its 2019 Ten-Year Site Plan, GPC plans to add a natural gas-fired combined cycle unit in 2024 after the expiration of the Shell PPA. The planned combined cycle addition will require a determination of need from the Commission.

Table 19: GPC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
			Sum	
Retiring Units				
2024	Crist 4	BIT – ST	75	
2025	Pea Ridge 1 – 3	NG – CT	12	
2026	Crist 5	BIT – ST	75	
Total Retirements			**162**	
New Units				
2024	Combined Cycle 2[1]	NG – CC	595	This unit requires a determination of need by the Commission.
Total New Units			**595**	
Net Additions			**433**	

Source: 2019 Ten-Year Site Plan

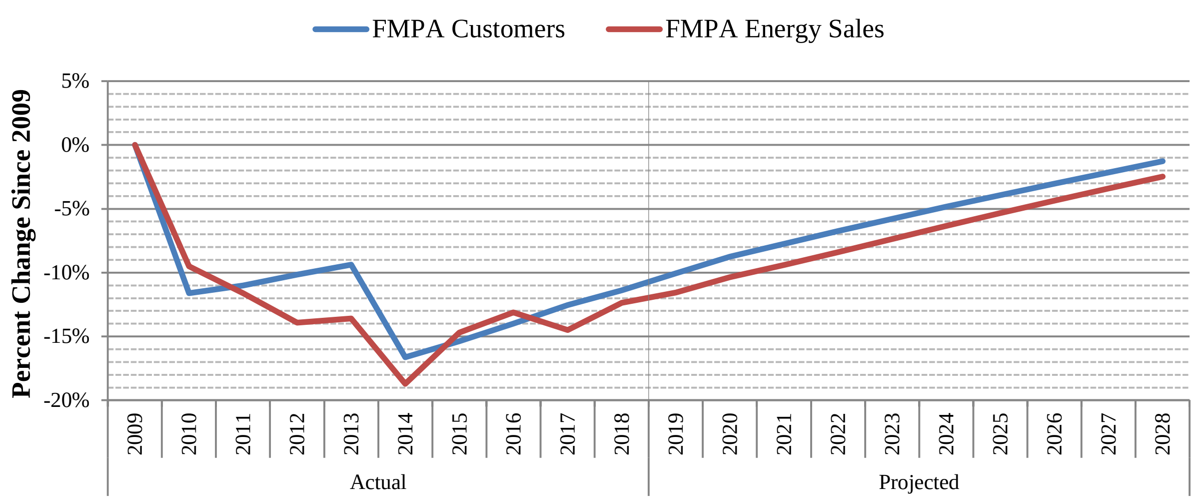
Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout Florida. 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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, FMPA had approximately 261,147 customers and annual retail energy sales of 5,771 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 30 illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2009. Over the last 10 years, FMPA's customer base has decreased by 11.38 percent, while retail sales have decreased by 12.36 percent. As illustrated, FMPA's retail energy sales are not anticipated to exceed its historic 2009 peak during the planning period. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, the City of Fort Meade in 2015, and the City of Green Cove Springs in 2019.

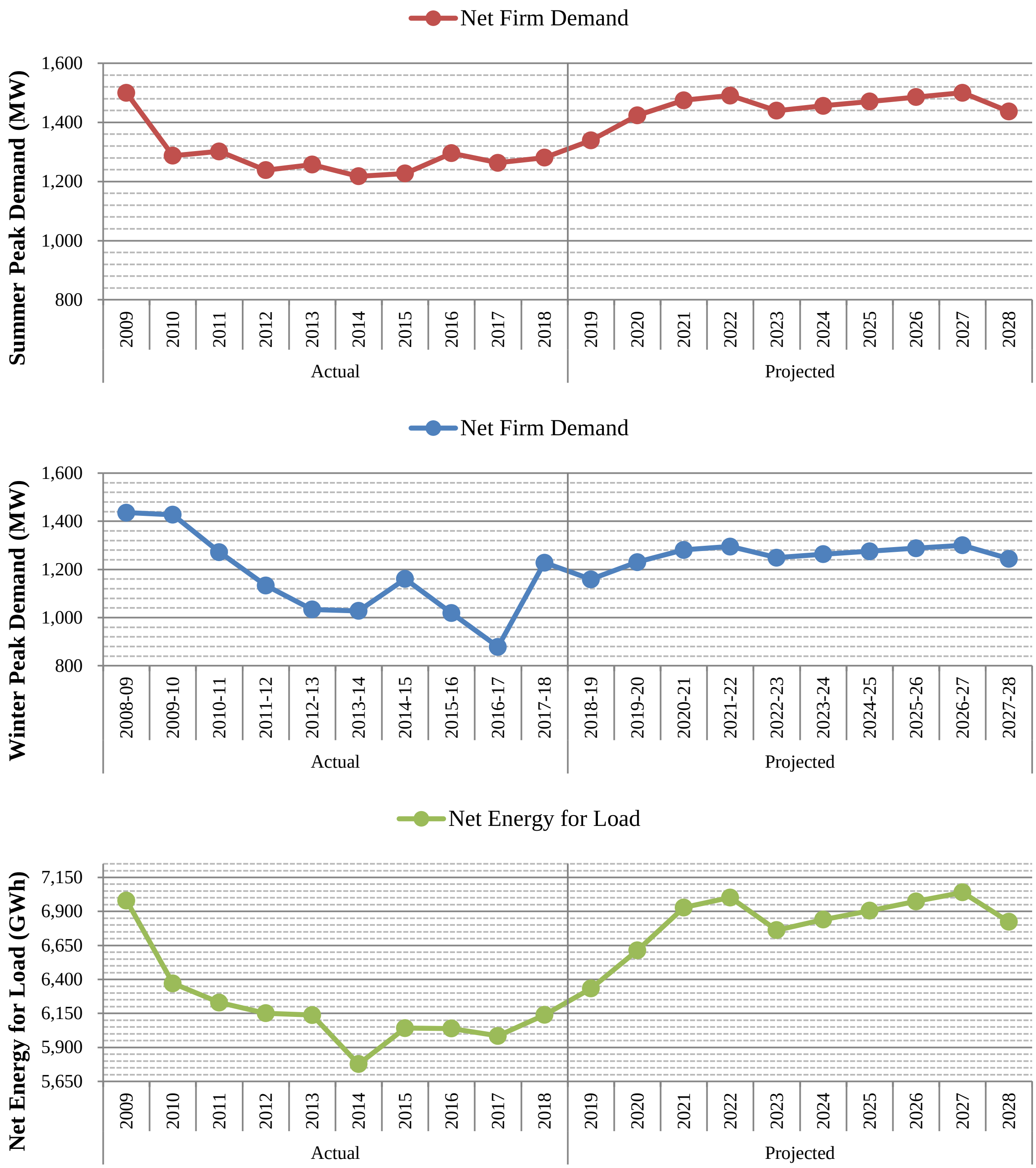
Figure 30: FMPA Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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 31: FMPA Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 20 shows FMPA's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects a decrease in energy generation from coal in 2028, but approximately 88.3 percent of energy would still be sourced from natural gas and nuclear.

Table 20: FMPA Energy Consumption by Fuel Type

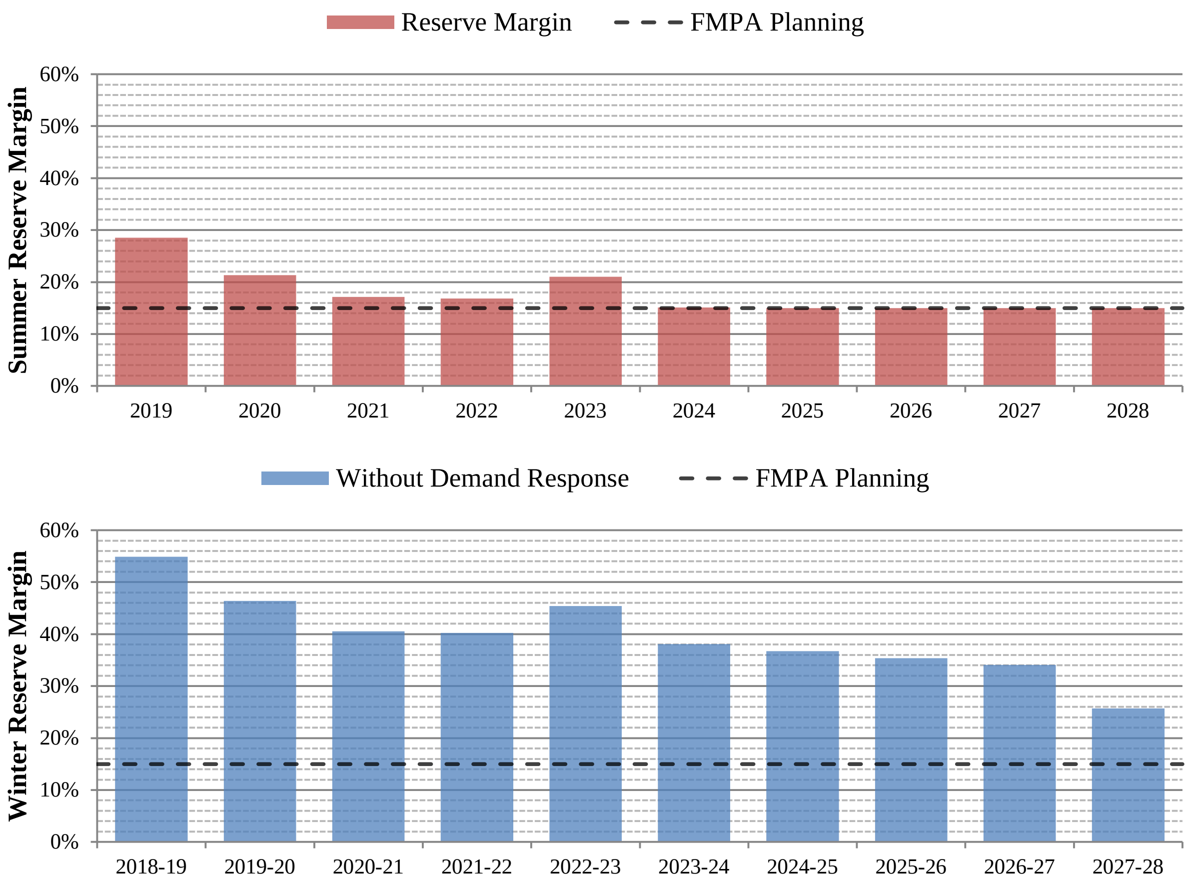
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	4,851	**79.0%**	5,635	**82.6%**
Coal	968	**15.8%**	529	**7.7%**
Nuclear	279	**4.5%**	391	**5.7%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	39	**0.6%**	269	**3.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**6,138**		**6,824**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 32 displays the forecast planning reserve margin for FMPA through the planning period for both seasons, with the impact of energy efficiency programs. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 32: FMPA Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

FMPA plans no unit additions or retirements during the planning period. However, as discussed above, several ARP member systems have elected to modify their contractual agreements with FMPA, such that FMPA no longer utilizes the member system's generation resources.

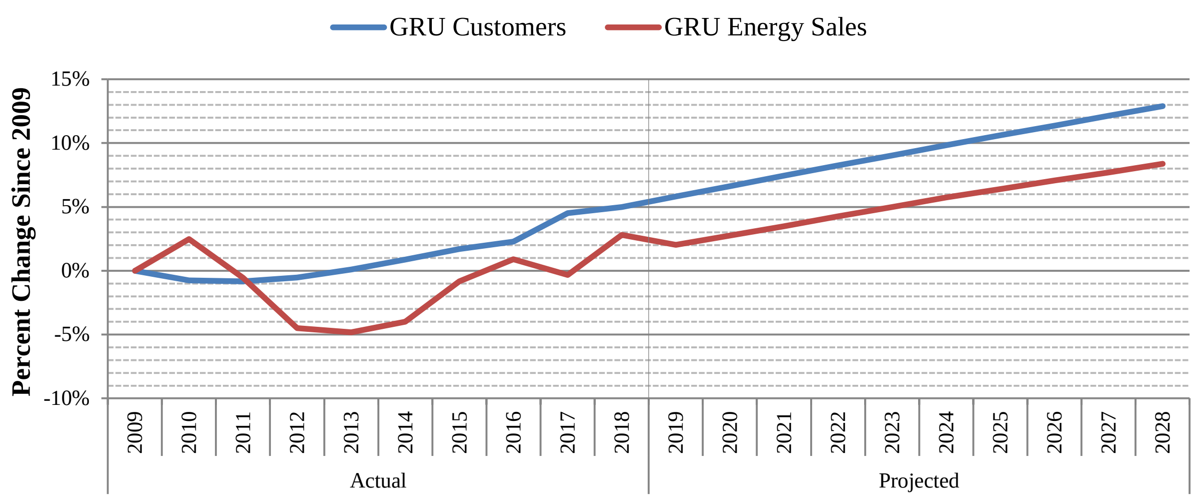
Gainesville Regional Utilities (GRU)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, GRU had approximately 97,681 customers and annual retail energy sales of 1,830 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 33 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, GRU's customer base has increased by 4.98 percent, while retail sales have increased by 2.81 percent.

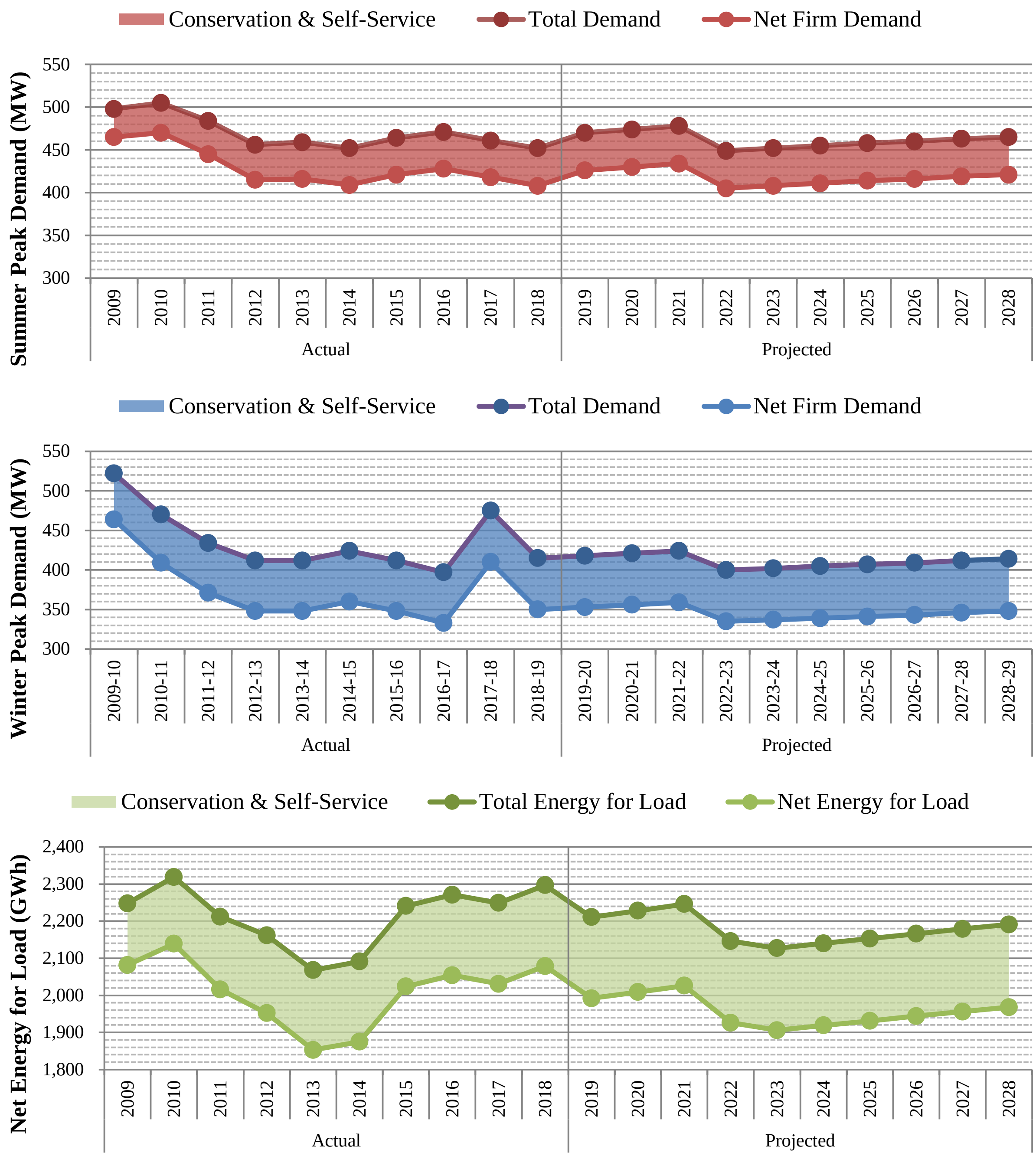
Figure 33: GRU Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 34 include the impact of these demand-side management programs.

Figure 34: GRU Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, natural gas was the primary fuel followed by renewables and coal respectively. By the year 2028, natural gas and renewables are expected to drop in usage while the energy obtained by burning coal is expected to increase.

Table 21: GRU Energy Consumption by Fuel Type

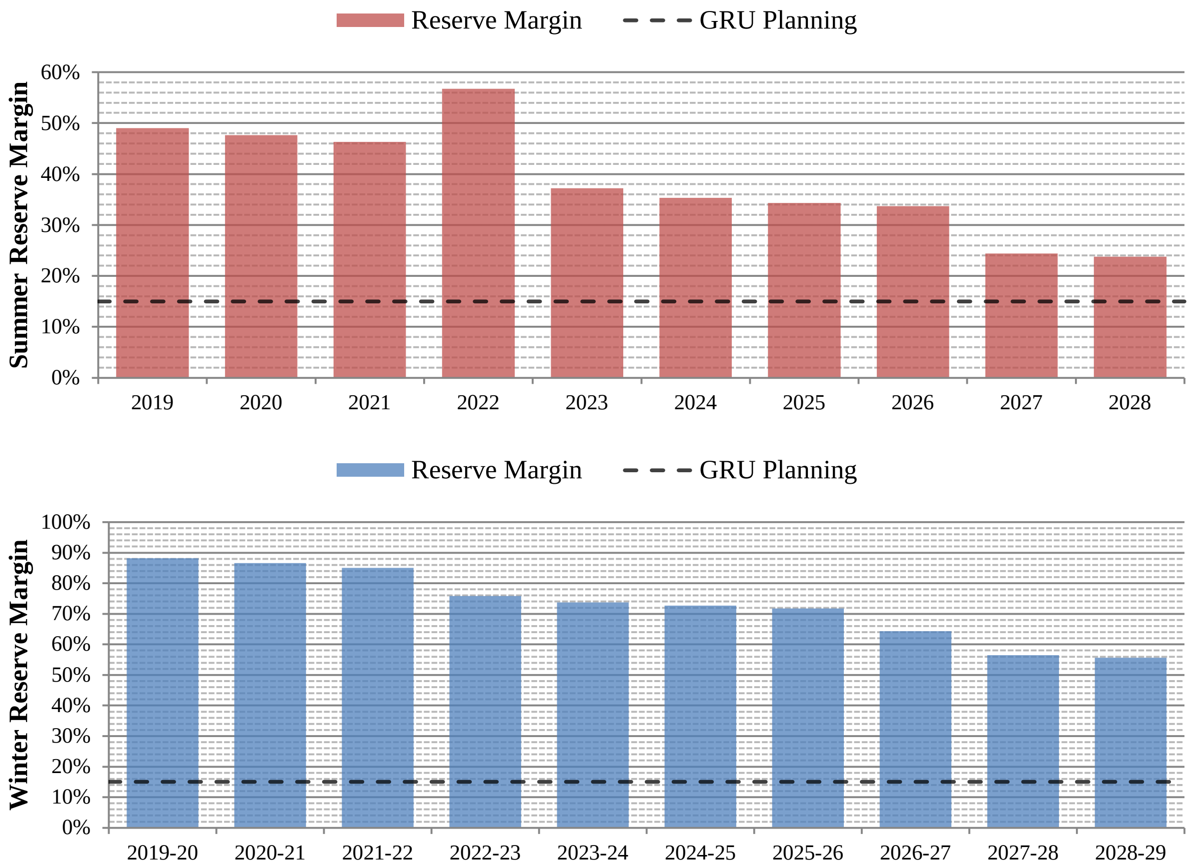
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	1,016	**48.9%**	903	**45.9%**
Coal	460	**22.1%**	720	**36.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	595	**28.6%**	300	**15.2%**
Interchange	7	**0.3%**	45	**2.3%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,079**		**1,968**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 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 55.9 percent of its summer net firm peak demand in 2018.

Figure 35: GRU Reserve Margin Forecast



Source: 2019 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 22. As a smaller utility, single units can have a large impact upon reserve margin.

Table 22: 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: 2019 Ten-Year Site Plan

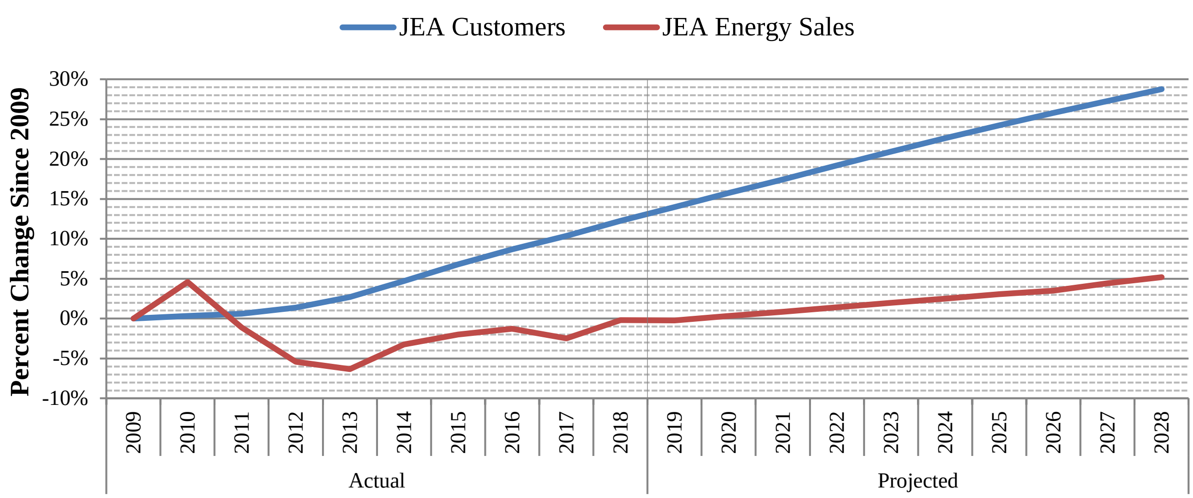
JEA

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, JEA had approximately 464,793 customers and annual retail energy sales of 12,085 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Figure 36 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, JEA's customer base has increased by 12.25 percent, while retail sales have decreased by 0.17 percent. As illustrated, JEA's retail energy sales are not anticipated to exceed its historic 2010 peak until 2028.

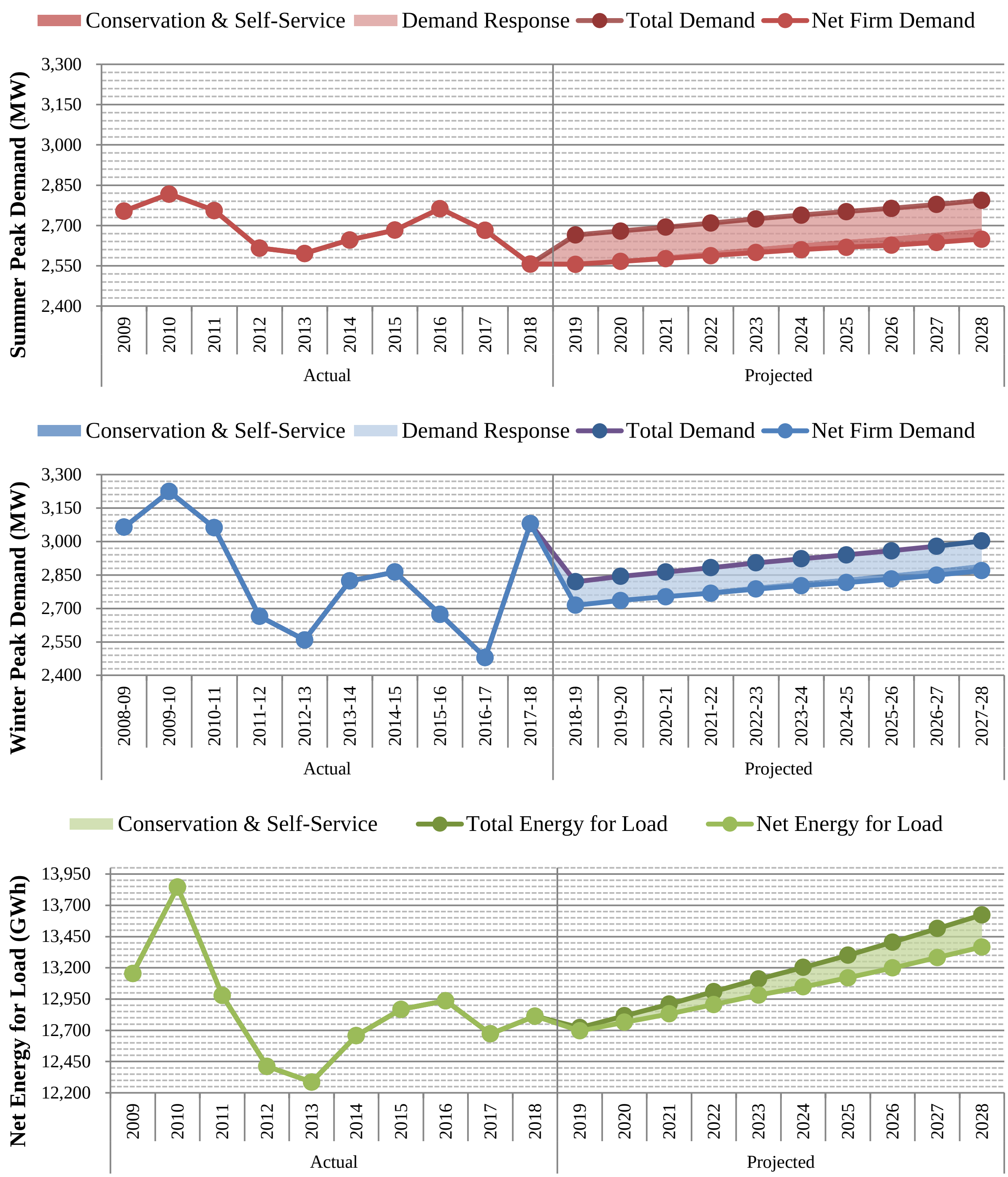
Figure 36: JEA Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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 37: JEA Demand and Energy Forecasts



Source: 2019 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. The Utility's 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. While natural gas was the dominant fuel source in 2018, coal was JEA's second most utilized fuel source. JEA's 2019 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 2028. JEA projects the third highest percentage of energy consumption from coal in 2028 of the TYSP Utilities.

Table 23: JEA Energy Consumption by Fuel Type

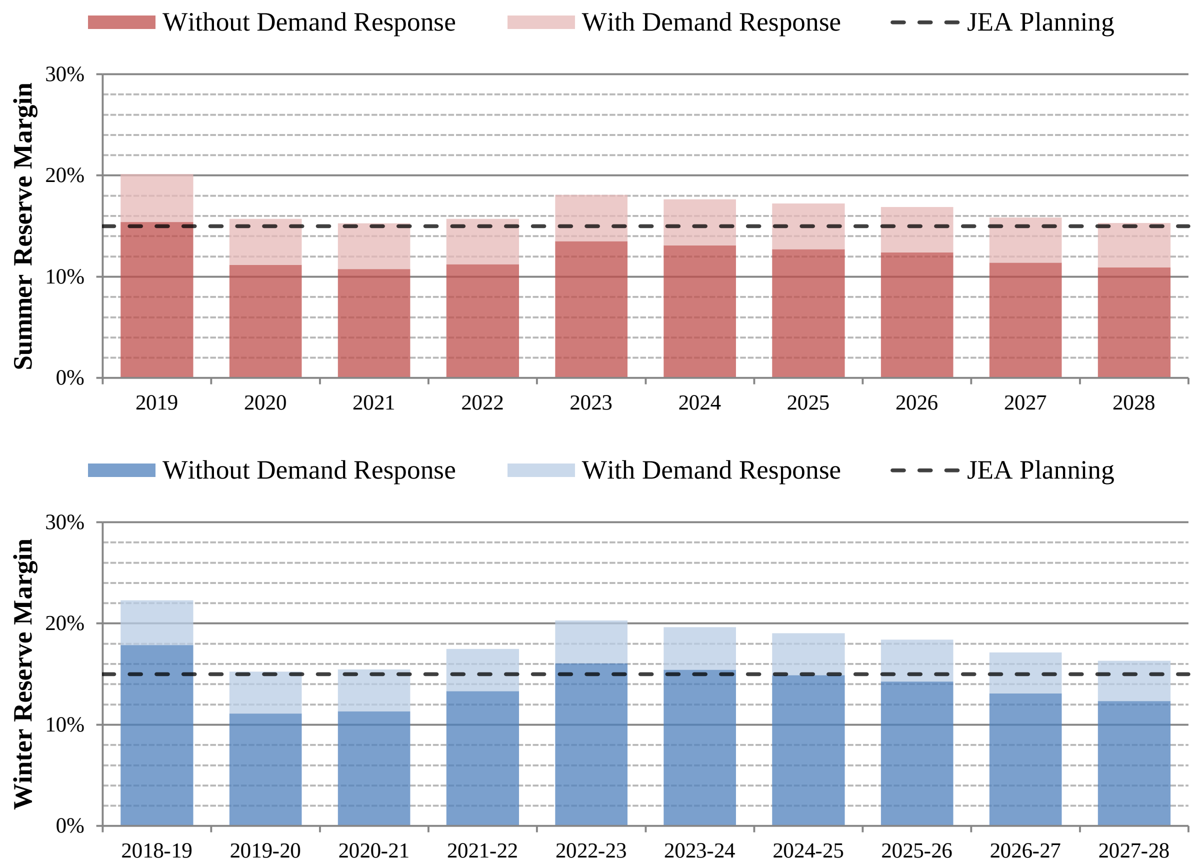
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	6,590	**51.4%**	6,275	**46.9%**
Coal	3,558	**27.8%**	4,808	**36.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	30	**0.2%**	1	**0.0%**
Renewable	149	**1.2%**	668	**5.0%**
Interchange	2,485	**19.4%**	1,615	**12.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,813**		**13,366**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 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 are controlled by its summer peak throughout the planning period.

Figure 38: JEA Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

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

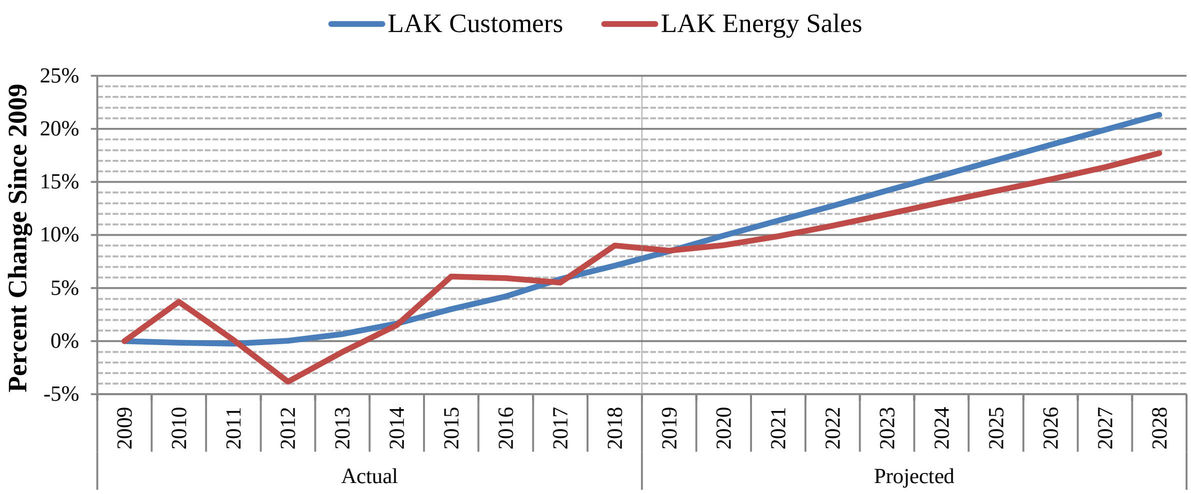
Lakeland Electric (LAK)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, LAK had approximately 130,657 customers and annual retail energy sales of 3,118 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Figure 39 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, LAK's customer base has increased by 7.10 percent, while retail sales have grown by 9.02 percent.

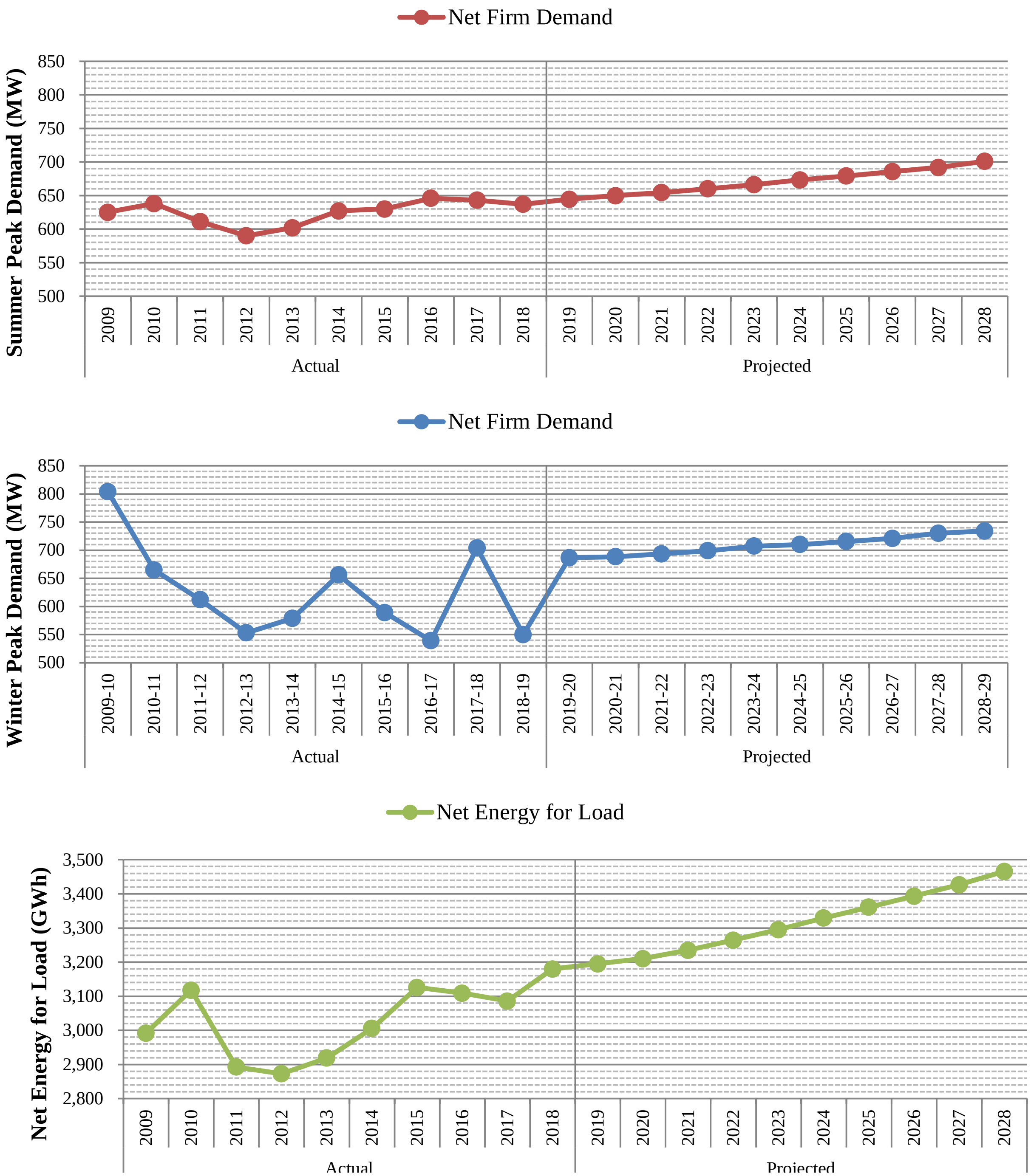
Figure 39: LAK Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 40: LAK Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 24 shows LAK's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. LAK uses natural gas as its primary fuel type for energy, with coal representing about 30 percent net energy for load. While natural gas usage is anticipated to remain stable, coal is projected to decrease by 2028.

Table 24: LAK Energy Consumption by Fuel Type

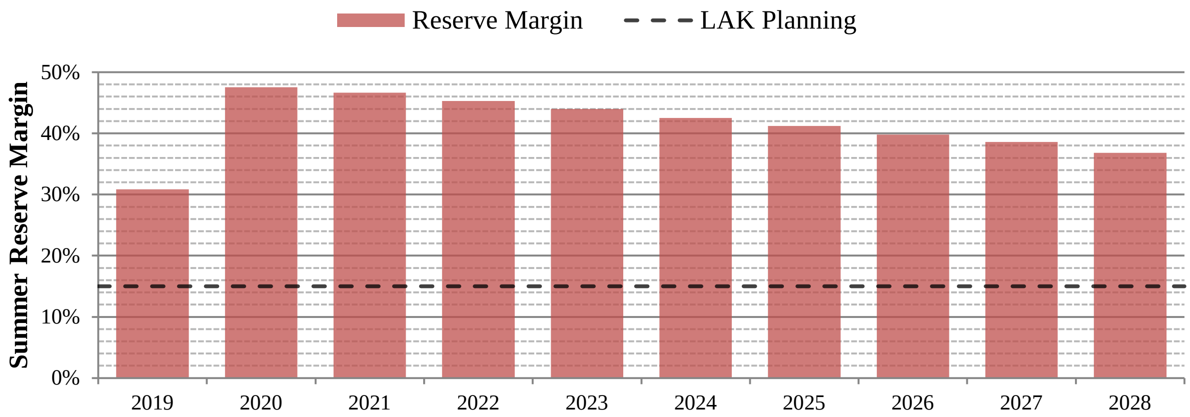
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	2,270	**71.4%**	2,471	**71.3%**
Coal	969	**30.5%**	508	**14.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	26	**0.8%**	27	**0.8%**
Interchange	-85	**-2.7%**	459	**13.2%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**3,180**		**3,466**	

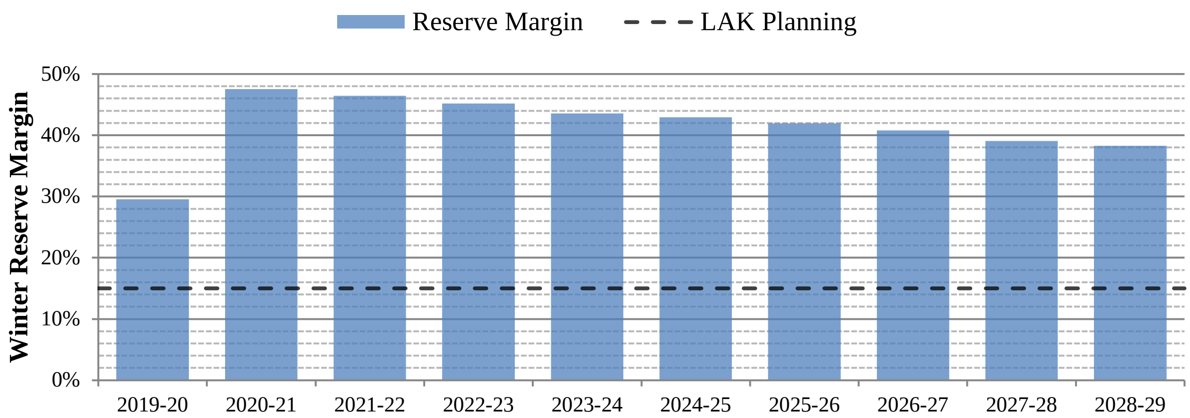
Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 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 53.1 percent of summer net firm peak demand in 2018.

Figure 41: LAK Reserve Margin Forecast





Source: 2019 Ten-Year Site Plan

Generation Resources

LAK plans on adding a single natural gas combustion turbine as shown in Table 25.

Table 25: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)
			Sum
New Units			
2020	C.D. McIntosh 2	NG – CT	115
Net Additions			**115**

Source: 2019 Ten-Year Site Plan and Data Responses

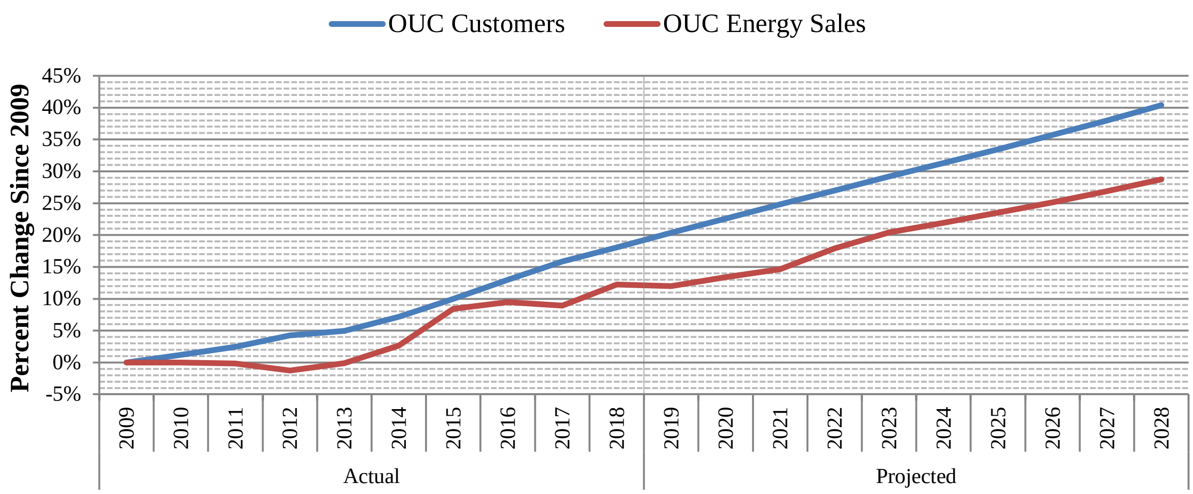
Orlando Utilities Commission (OUC)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, OUC had approximately 241,628 customers and annual retail energy sales of 6,769 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 42 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, OUC's customer base has increased by 18.07 percent, while retail sales have grown by 12.25 percent.

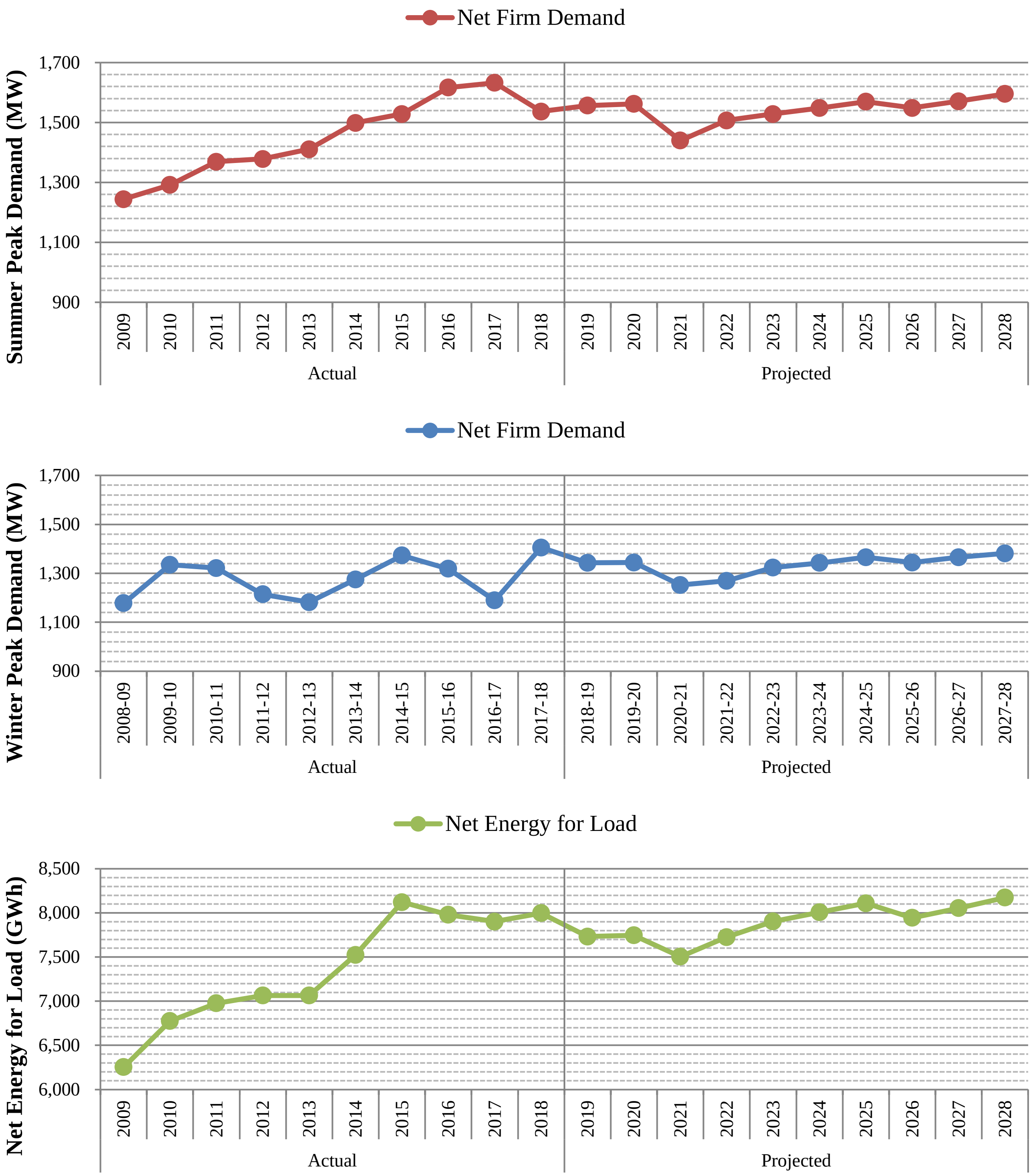
Figure 42: OUC Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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.

Figure 43: OUC Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, approximately 53 percent of OUC's net energy for load was met with coal, while natural gas, the second most-used fuel, met 39 percent. By 2028, OUC projects to meet 62 percent of its net energy for load with natural gas, while coal use is expected to decrease to 24 percent.

Table 26: OUC Energy Consumption by Fuel Type

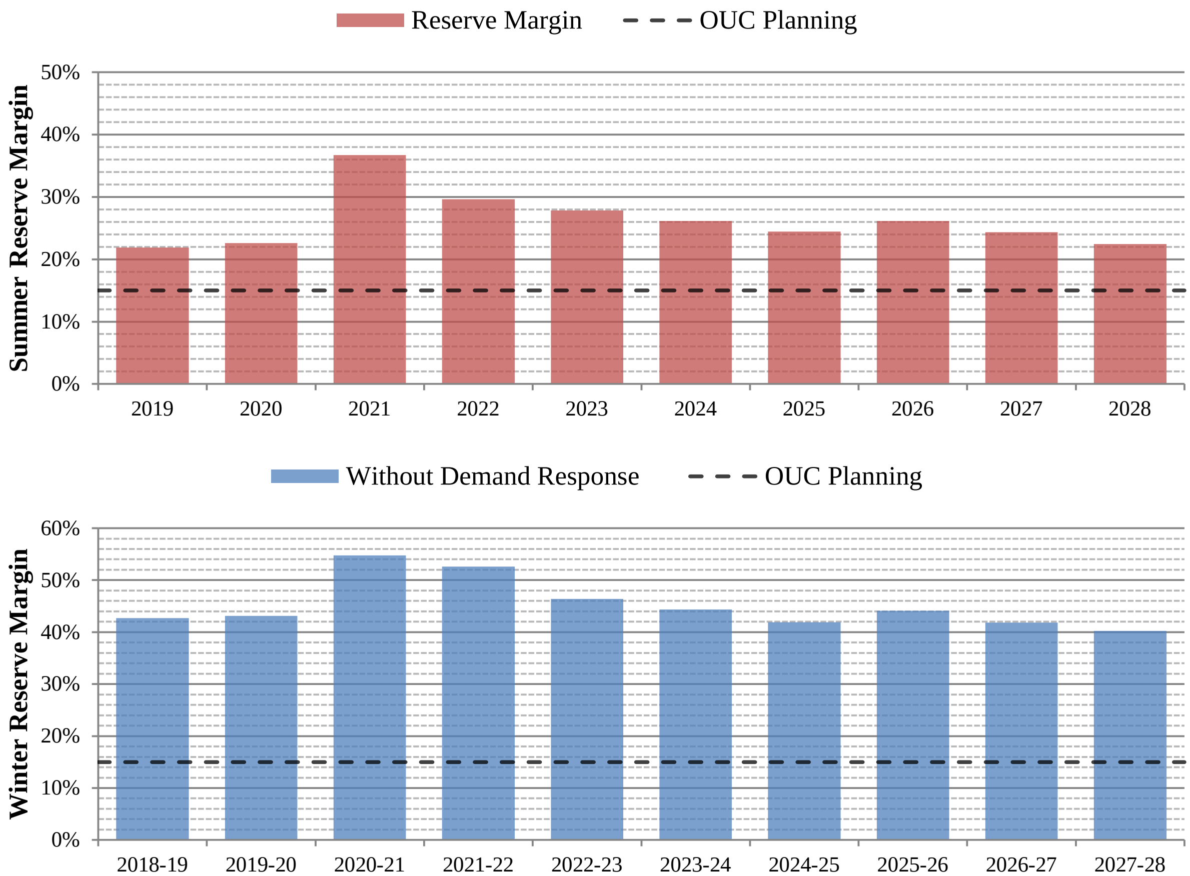
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	3,138	**39.2%**	5,037	**61.6%**
Coal	4,204	**52.6%**	1,964	**24.0%**
Nuclear	470	**5.9%**	561	**6.9%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	185	**2.3%**	611	**7.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,997**		**8,173**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 44 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 44: OUC Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

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

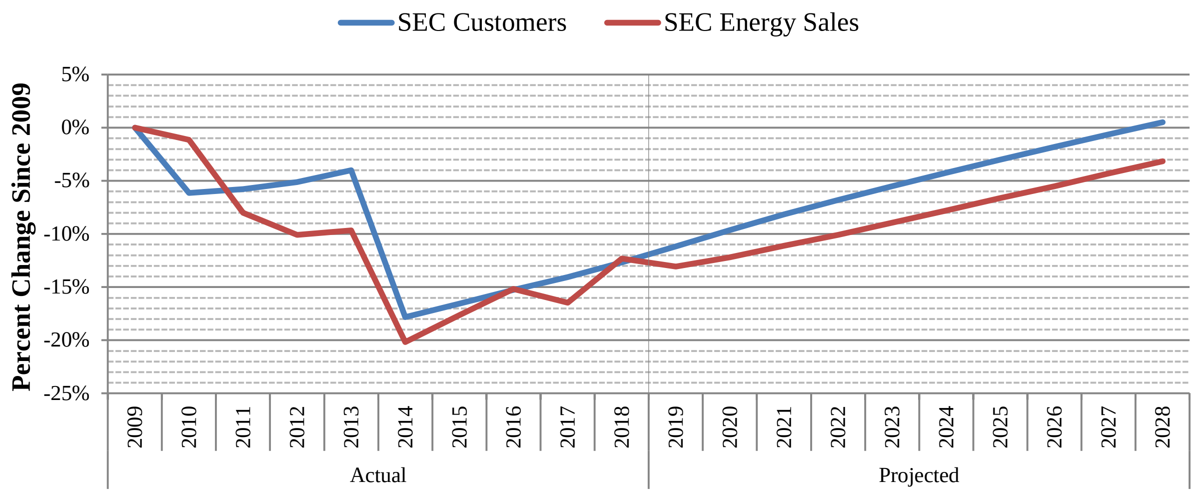
Seminole Electric Cooperative (SEC)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, SEC member cooperatives had approximately 787,055 customers and annual retail energy sales of 14,235 GWh or approximately 6.2 percent of Florida's annual retail energy sales. Figure 45 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, SEC's customer base has decreased by 12.66 percent, and retail sales have decreased 12.32 percent. As illustrated, SEC's retail energy sales are not anticipated to exceed its historic 2009 peak during this planning period. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

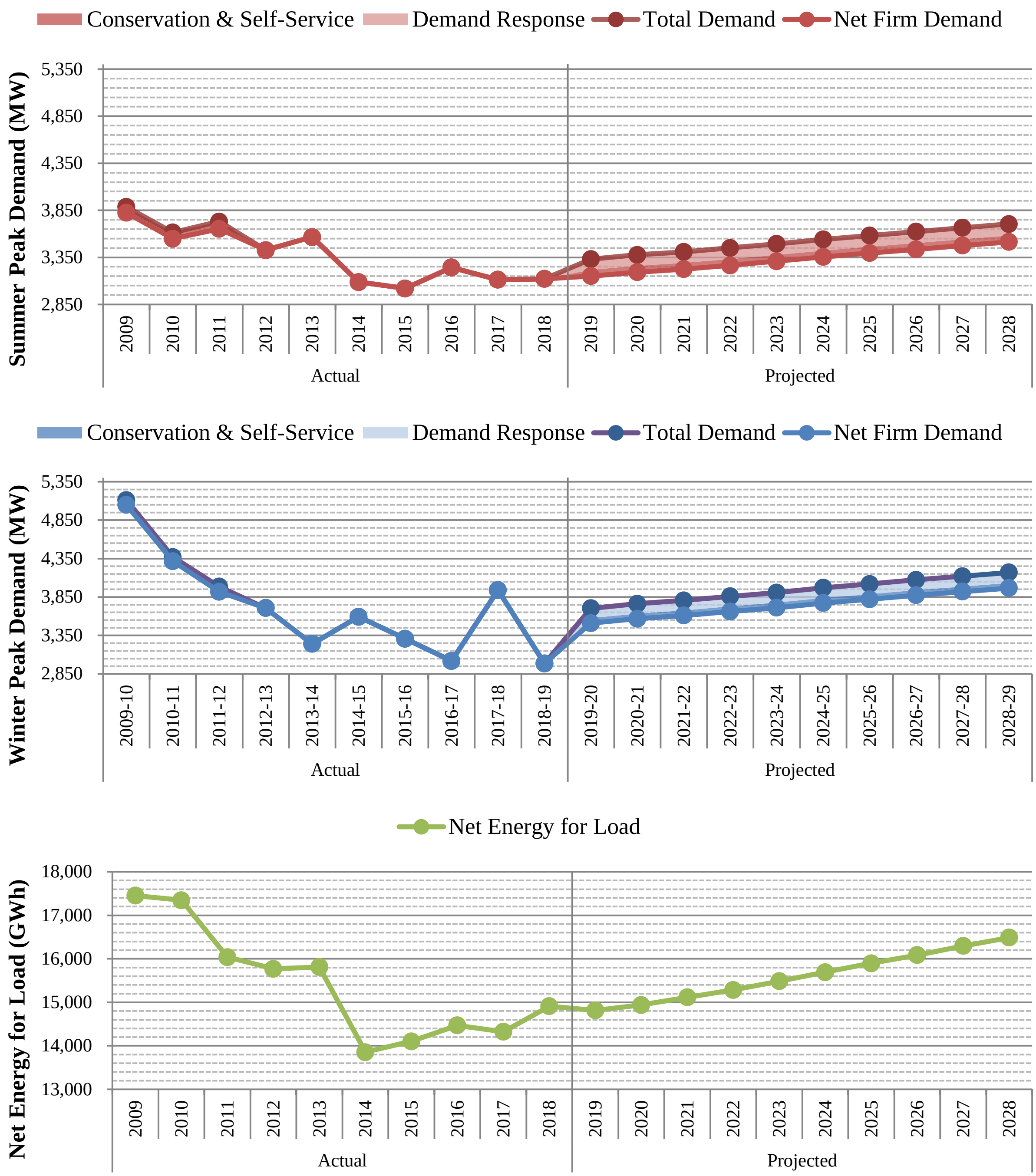
Figure 45: SEC Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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 46.

Figure 46: SEC Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 27 shows SEC's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, SEC used coal as its primary source of fuel, while natural gas was the second most used fuel. By 2028 natural gas usage is expected to become the primary fuel source.

Table 27: SEC Energy Consumption by Fuel Type

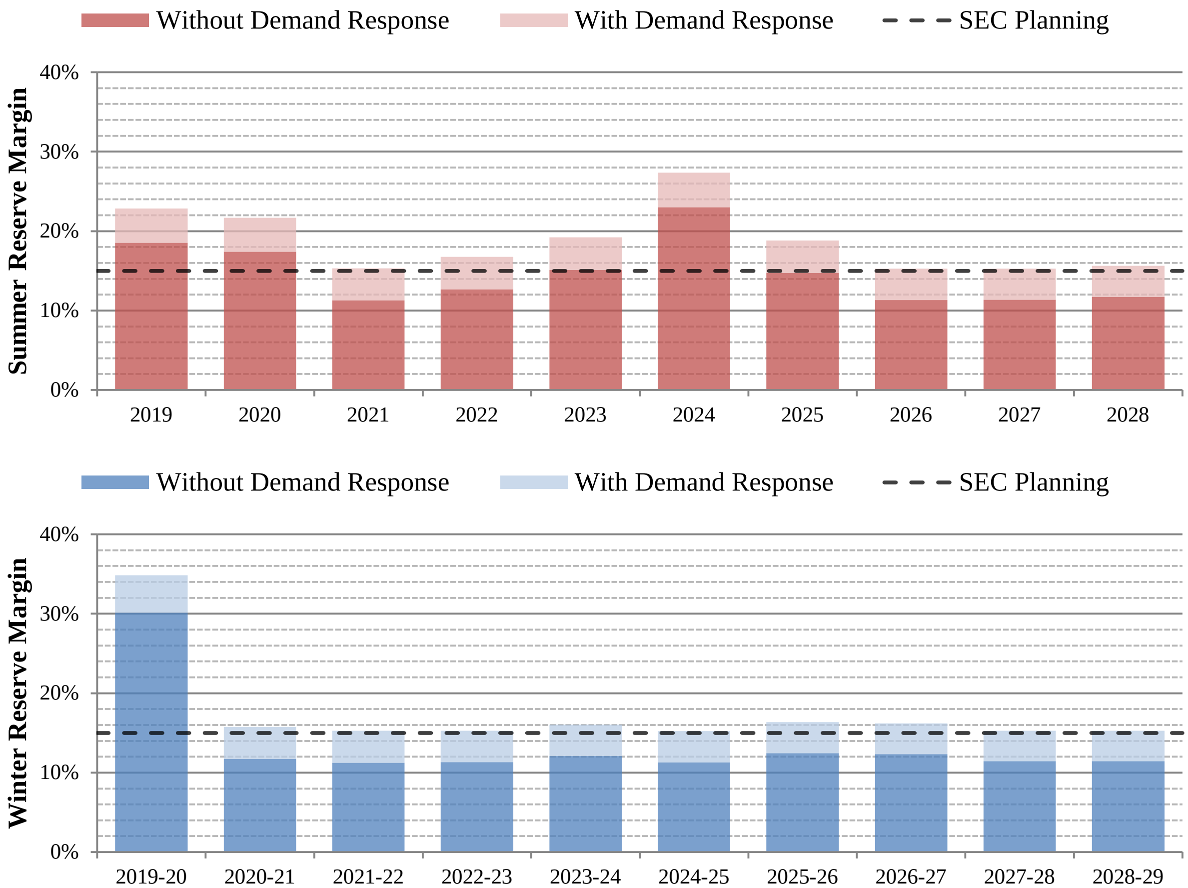
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	3,619	**24.3%**	9,603	**58.2%**
Coal	7,599	**51.0%**	2,839	**17.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	20	**0.1%**	10	**0.1%**
Renewable	610	**4.1%**	111	**0.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	3,064	**20.5%**	3,926	**23.8%**
Total	**14,912**		**16,489**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 47 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 47: SEC Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add one unit during the planning period, as described in Table 28. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[26] Consistent with its need determination filing, SEC plans to retire one of its coal-fired SGS units in 2023, and the Seminole CC Facility is expected to be in-service by 2022.

Table 28: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2023	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
Total New Units			**1,108**	
Net Additions			**478**	

Source: 2019 Ten-Year Site Plan

[26]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.*

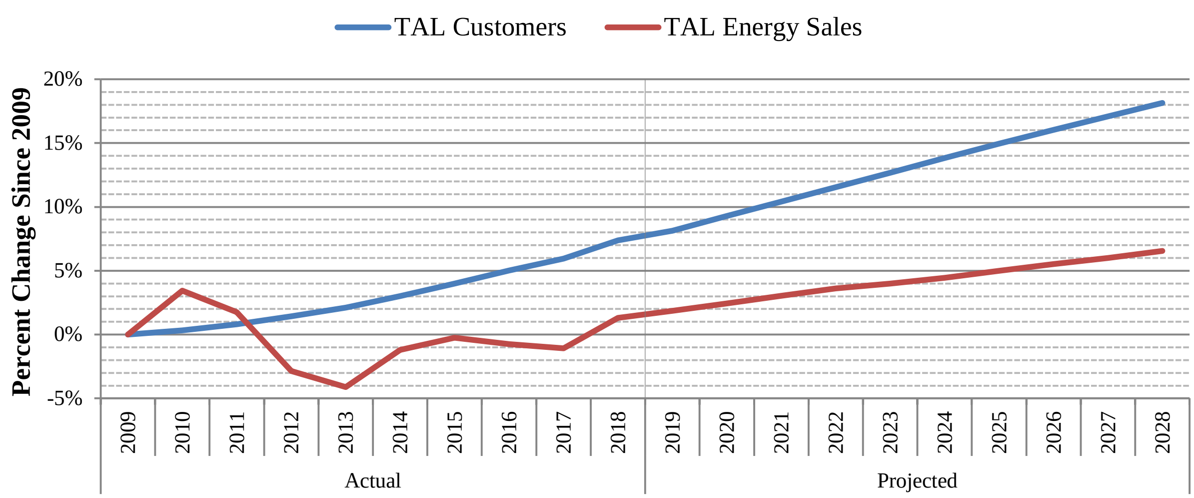
City of Tallahassee Utilities (TAL)

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 2019 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2018, TAL had approximately 121,677 customers and annual retail energy sales of 2,698 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 48 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, TAL's customer base has increased by 7.39 percent, while retail sales have increased by 1.31 percent. As illustrated, TAL's retail energy sales are not anticipated to exceed its historic 2010 peak until 2022.

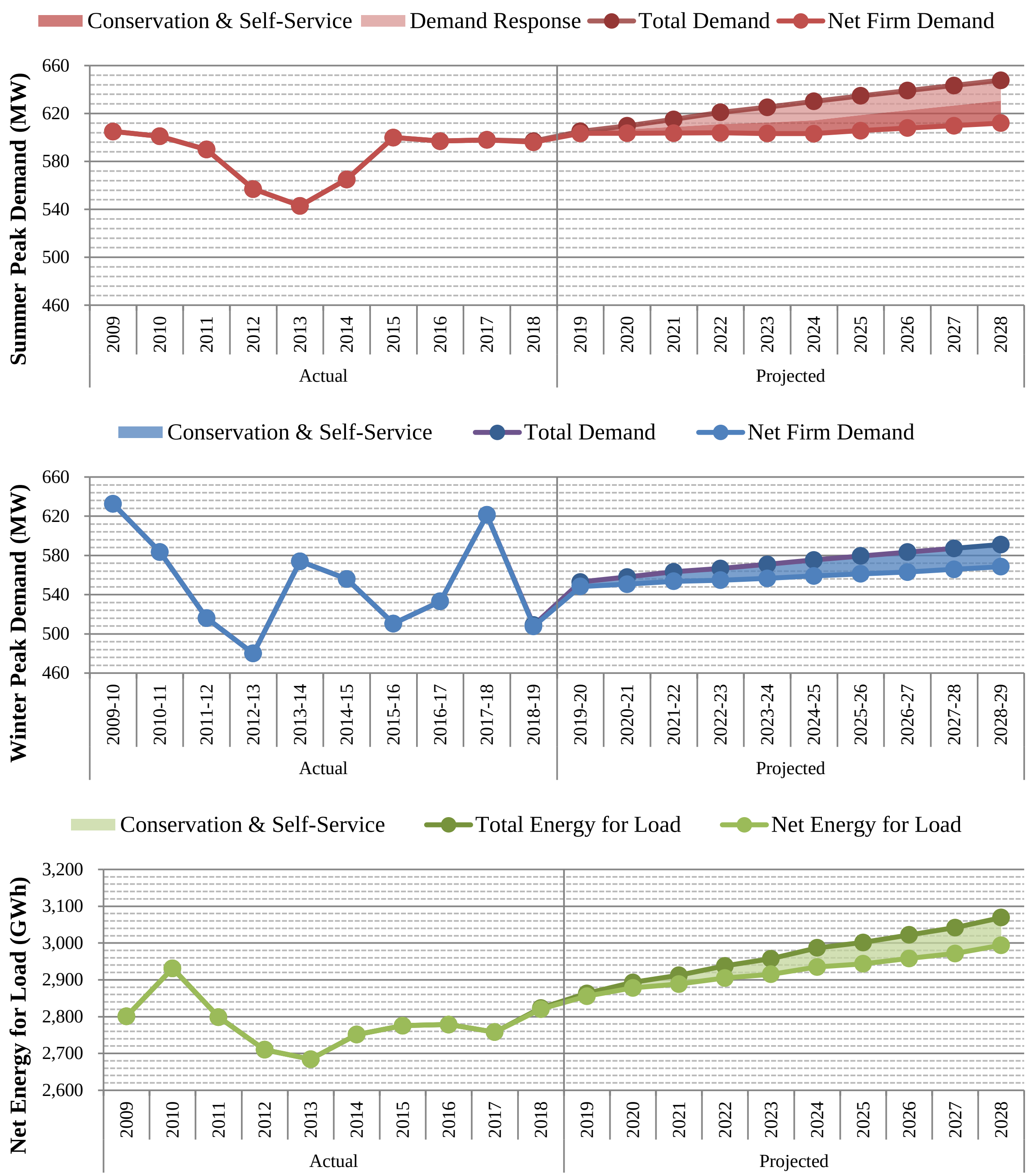
Figure 48: TAL Growth



Source: 2019 Ten-Year Site Plan

The three graphs in Figure 49 shows TAL's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. 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 49: TAL Demand and Energy Forecasts



Source: 2019 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 29 shows TAL's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities and the use of oil as a backup fuel. Natural gas is anticipated to remain the primary fuel source on the system.

Table 29: TAL Energy Consumption by Fuel Type

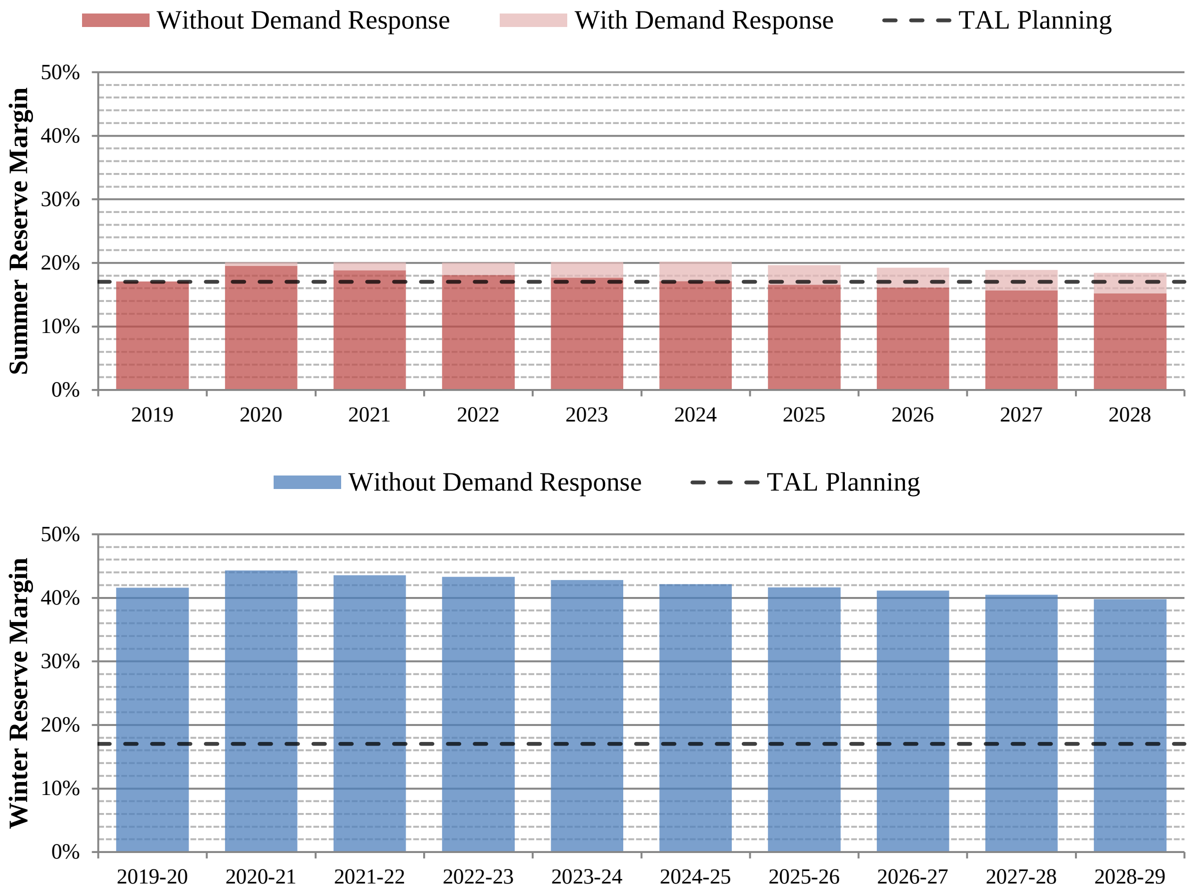
Fuel Type	Net Energy for Load			
	2018		2028	
	GWh	%	GWh	%
Natural Gas	2,808	**99.6%**	2,889	**96.5%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	59	**2.1%**	118	**3.9%**
Interchange	-48	**-1.7%**	-13	**-0.4%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,820**		**2,994**	

Source: 2019 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 50 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 50: TAL Reserve Margin Forecast



Source: 2019 Ten-Year Site Plan

Generation Resources

Table 30 shows TAL's additions and retirements over the 2019-2028 planning period. TAL plans on retiring the Corn Hydroelectric station in early 2019. On June 5, 2017, TAL filed an Application for Surrender of License for the hydroelectric station with the Federal Energy Regulatory Commission. In this filing, TAL explains its primary motivation for retiring the plant is to reduce cost and risk, the benefits from the plant's as-available energy not outweighing the costs of operation and maintenance. TAL also plans to add several natural gas-fired internal combustion units to its system from 2019-2020.

Table 30: TAL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2019	Corn Hydro 1 – 3	HY	12
Total Retirements			**12**
New Units			
2019	Hopkins 1 – 4	NG – IC	74
2020	Hopkins 5	NG – IC	18
Total New Units			**92**
Net Additions			**80**

Source: 2019 Ten-Year Site Plan