REVIEW OF THE

2022 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA
PUBLIC
SERVICE
COMMISSION

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Table of Contents

List of Figures .... **iii**
List of Tables .... **iv**
List of Ten-Year Site Plan Utilities v
Unit Type and Fuel Abbreviations v
Executive Summary **1**
Review of the 2022 Ten-Year Site Plans 2
Future Considerations 5
Conclusion 6
Introduction **7**
Statutory Authority 7
Additional Resources 8
Structure of the Commission's Review 9
Conclusion 9
Statewide Perspective **11**
Load Forecasting **13**
Electric Customer Composition 13
Growth Projections 14
Peak Demand 16
Electric Vehicles 17
Demand-Side Management (DSM) 21
Forecast Load & Peak Demand 22
Forecast Methodology 25
Accuracy of Retail Energy Sales Forecast 26
Renewable Generation **29**
Existing Renewable Resources 29
Utility-Owned Renewable Generation 30
Non-Utility Renewable Generation 30
Planned Renewable Resources 31
Energy Storage Outlook 33
Traditional Generation **35**
Existing Generation 35
Impact of EPA Rules 36
Modernization and Efficiency Improvements 37
Planned Retirements 38
Reliability Requirements 39
Fuel Price Forecast 41

Fuel Diversity ... 42
New Generation Planned ... 43
Commission's Authority Over Siting ... 44
New Power Plants by Fuel Type ... 45
Transmission ... 45
Utility Perspectives ... 47
Florida Power & Light Company (FPL) ... 49
Duke Energy Florida, LLC (DEF) ... 57
Tampa Electric Company (TECO) ... 63
Florida Municipal Power Agency (FMPA) ... 69
Gainesville Regional Utilities (GRU) ... 75
JEA ... 79
Lakeland Electric (LAK) ... 85
Orlando Utilities Commission (OUC) ... 91
Seminole Electric Cooperative (SEC) ... 97
City of Tallahassee Utilities (TAL) ... 103

List of Figures

Figure 1: State of Florida - Growth in Customers and Sales 2
Figure 2: State of Florida - Electricity Generation Sources 4
Figure 3: State of Florida - Current and Projected Installed Capacity 5
Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Sales 8
Figure 5: State of Florida - Electric Customer Composition in 2021 13
Figure 6: National - 20 Year Average Climate Data by State (Continental US) 14
Figure 7: State of Florida - Growth in Customers and Sales 15
Figure 8: TYSP Utilities - Example Daily Load Curves 16
Figure 9: TYSP Utilities - Daily Peak Demand (2021 Actual) 17
Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy 24
Figure 11: State of Florida - Current and Projected Renewable Resources 32
Figure 12: TYSP Utilities - Planned Solar Installations 32
Figure 13: State of Florida - Electric Utility Installed Capacity by Decade 35
Figure 14: State of Florida - Projected Reserve Margin by Season 40
Figure 15: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities 41
Figure 16: State of Florida - Natural Gas Generation 42
Figure 17: State of Florida - Historic and Forecast Generation by Fuel Type 43
Figure 18: State of Florida - Current and Projected Installed Capacity 44
Figure 19: FPL Growth 50
Figure 20: FPL Demand and Energy Forecasts 52
Figure 21: FPL Reserve Margin Forecast 54
Figure 22: DEF Growth 58
Figure 23: DEF Demand and Energy Forecasts 59
Figure 24: DEF Reserve Margin Forecast 61
Figure 25: TECO Growth 64
Figure 26: TECO Demand and Energy Forecasts 65
Figure 27: TECO Reserve Margin Forecast 67
Figure 28: FMPA Growth 70
Figure 29: FMPA Demand and Energy Forecasts 71
Figure 30: FMPA Reserve Margin Forecast 73
Figure 31: GRU Growth 75
Figure 32: GRU Demand and Energy Forecasts 76
Figure 33: GRU Reserve Margin Forecast 78
Figure 34: JEA Growth 80
Figure 35: JEA Demand and Energy Forecasts 81
Figure 36: JEA Reserve Margin Forecast 83
Figure 37: LAK Growth 86
Figure 38: LAK Demand and Energy Forecasts 87
Figure 39: LAK Reserve Margin Forecast 89
Figure 40: OUC Growth 92
Figure 41: OUC Demand and Energy Forecasts 93
Figure 42: OUC Reserve Margin Forecast 95
Figure 43: SEC Growth 98
Figure 44: SEC Demand and Energy Forecasts 99
Figure 45: SEC Reserve Margin Forecast 101
Figure 46: TAL Growth 104
Figure 47: TAL Demand and Energy Forecasts 105
Figure 48: TAL Reserve Margin Forecast 107

List of Tables

Table 1: TYSP Utilities - Renewable Energy Generation ... 3
Table 2: TYSP Utilities - Estimated Number of Electric Vehicles ... 18
Table 3: TYSP Utilities - Estimated Number of Public EV Charging Stations ... 19
Table 4: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh) ... 19
Table 5: TYSP Utilities – Estimated Electric Vehicle Impact – Seasonal Peak Demand ... 20
Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts ... 26
Table 7: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis ... 27
Table 8: State of Florida - Existing Renewable Resources ... 29
Table 9: State of Florida - Customer-Owned Renewable Growth ... 31
Table 10: State of Florida - Electric Generating Units to be Retired ... 38
Table 11: TYSP Utilities - Planned Natural Gas Units ... 45
Table 12: State of Florida - Planned Transmission Lines ... 46
Table 13: FPL and GPC Energy Generation by Fuel Type ... 53
Table 14: FPL Generation Resource Changes ... 55
Table 15: DEF Energy Generation by Fuel Type ... 60
Table 16: DEF Generation Resource Changes ... 62
Table 17: TECO Energy Generation by Fuel Type ... 66
Table 18: TECO Generation Resource Changes ... 68
Table 19: FMPA Energy Generation by Fuel Type ... 72
Table 20: FMPA Generation Resource Changes ... 73
Table 21: GRU Energy Generation by Fuel Type ... 77
Table 22: GRU Generation Resource Changes ... 78
Table 23: JEA Energy Generation by Fuel Type ... 82
Table 24: JEA Energy Generation by Fuel Type ... 83
Table 25: LAK Energy Generation by Fuel Type ... 88
Table 26: LAK Generation Resource Changes ... 89
Table 27: OUC Energy Generation by Fuel Type ... 94
Table 28: OUC Generation Resource Changes ... 96
Table 29: SEC Energy Generation by Fuel Type ... 100
Table 30: SEC Generation Resource Changes ... 102
Table 31: TAL Energy Generation by Fuel Type ... 106

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
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	Bituminous Coal	BIT
	Distillate Fuel Oil	DFO
	Landfill Gas	LFG
	Natural Gas	NG

Executive Summary

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

The Commission's annual review of utility Ten-Year Site Plans is non-binding as required by Florida Statutes (F.S.), 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, F.S., each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2022 Ten-Year Site Plans for Florida's electric utilities, filed by 10 reporting utilities.[1]

[1] Investor-owned utilities filing 2022 Ten-Year Site Plans include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2022 Ten-Year Site Plans include Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. Seminole Electric Cooperative also filed a 2022 Ten-Year Site Plan. FPL initially submitted four versions of its Ten-Year Site Plan, consisting of a Business As Usual Plan using its traditional planning methodology, a Recommended Plan using a novel extreme winter planning methodology, and two additional plans based on potential federal legislation to be used for information purposes only. On July 11, 2022 FPL submitted a letter withdrawing its Recommended Plan. Only the Business As Usual Plan was utilized for this report.

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.

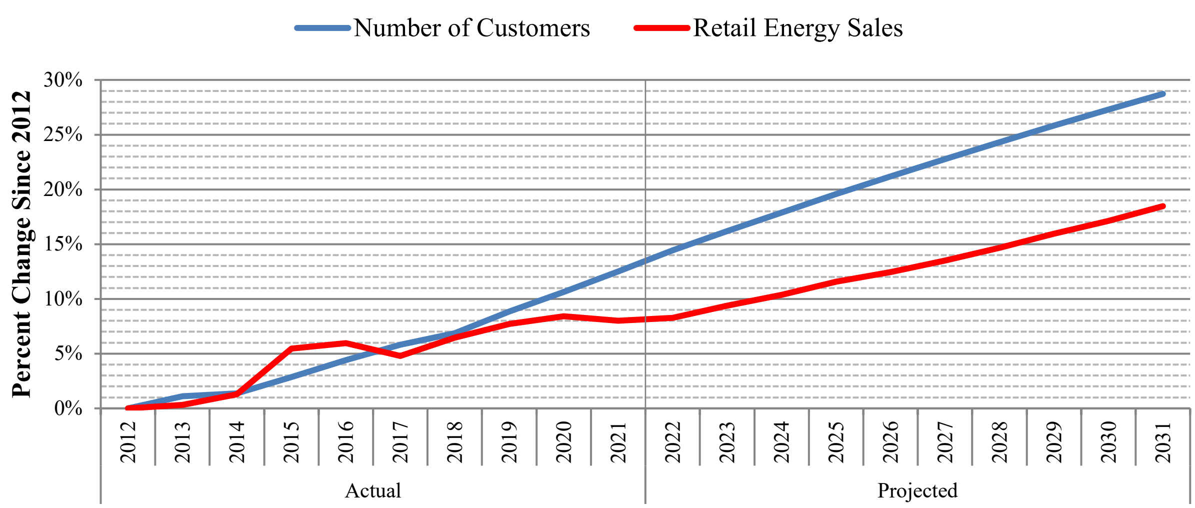
Review of the 2022 Ten-Year Site Plans

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 customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested forecasting methodologies, which are consistent with industrywide practices used in generation planning. Figure 1 provides the historical and forecasted trends in customer growth and energy sales.

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



Source: FRCC 2022 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 7,584 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar photovoltaic (PV) generation which makes up approximately 80 percent of Florida's existing renewables. Notably, Florida electric customers had installed 1,177 MW of demand-side renewable capacity by the end of 2021, an increase of 41 percent from 2020.

Florida's total renewable resources are expected to increase by an estimated 15,894 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels. Also, several utilities plan on adding battery storage totaling 2,462 MW which would increase firm capacity available during system peaks.

Table 1 provides a breakdown of each TYSP utility's actual 2021 and projected 2031 generation from renewables, in gigawatt-hours (GWh) and as a percentage of the net energy for load (NEL). Renewable energy as a percent of NEL is expected to increase from 5.2 percent in 2021 to 18.1 percent in 2031. Solar generation increases from approximately 67 percent of all renewable energy in 2021 to 95 percent of all renewable energy by 2031.

Table 1: State of Florida - Renewable Energy Generation

Utility	2021 Actual			2031 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL[3]	136,757	7,187	5.26%	149,499	28,816	19.28%
DEF	45,065	1,551	3.44%	44,872	9,983	22.25%
TECO	21,033	1,252	5.95%	21,931	4,481	20.43%
FMPA	6,937	154	2.22%	6,823	757	11.09%
GRU	1,952	612	31.35%	1,967	586	29.79%
JEA	12,540	166	1.32%	13,734	82	0.60%
LAK	3,304	26	0.79%	3,516	153	4.35%
OUC	7,548	349	4.62%	8,515	4,764	55.95%
TAL	2,729	113	4.14%	2,985	116	3.90%
SEC	15,541	489	3.15%	17,711	766	4.32%
State of Florida	260,004	13,468	5.18%	279,454	50,647	18.12%

Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

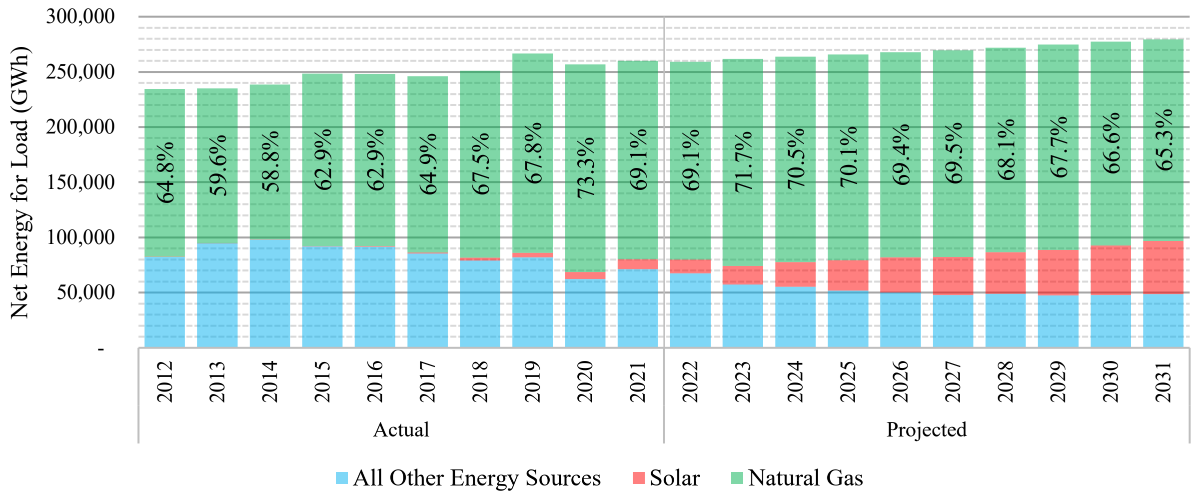
Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,389 MW of traditional generation over the planning horizon, with natural gas plant additions offset by coal and oil retirements. Natural gas electric generation,

[3] FPL's values in 2021 include Gulf Power Company, which was a separate entity during 2021.

as a percent of NEL, is expected to decline from 69 percent in 2022 to 65 percent over the planning horizon. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida compared to solar and all other energy sources combined. The total energy produced by solar generation is projected to exceed coal-fired generation by 2023, and nuclear based generation by 2026.

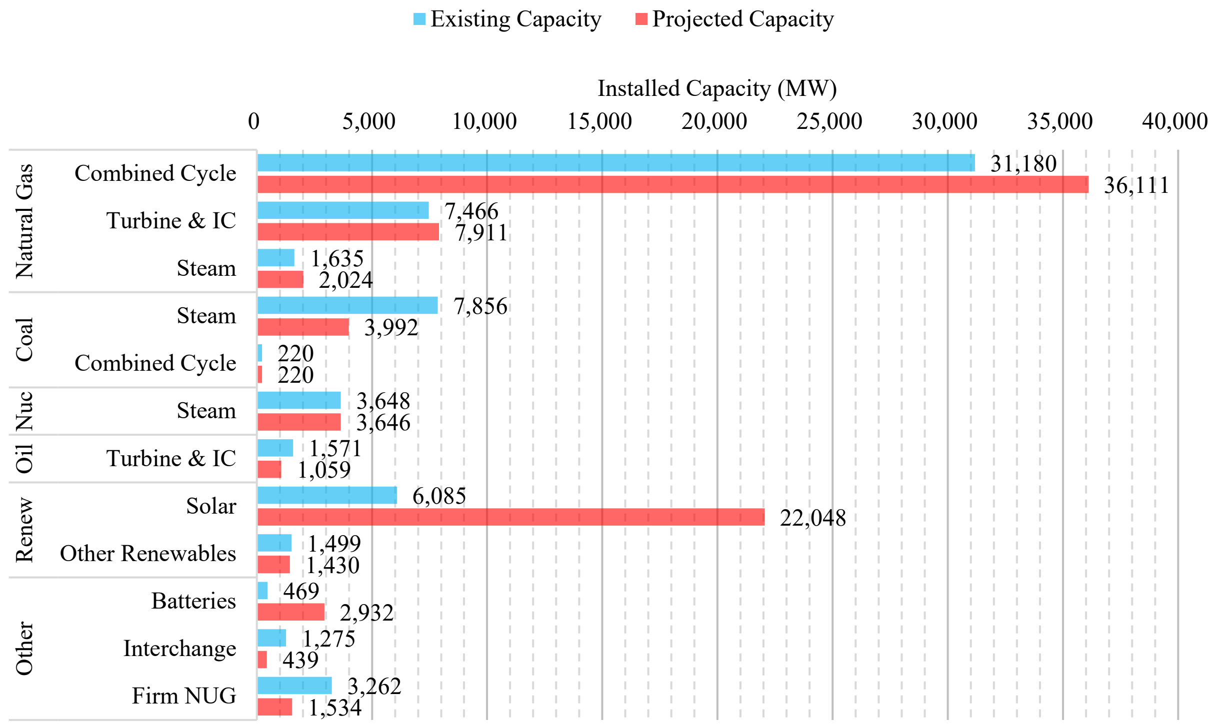
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2013-2022 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2022 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. Solar generation is projected to be the second highest category of installed capacity by the end of the 10-year planning period.

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



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local, regional, and state agencies to assist in the certification process. During the next 10 years, there are no new units planned that require a determination of need from the Commission pursuant to Section 403.519, F.S.

Future Considerations

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

In order to prepare for and to accommodate the inevitable increase in electric vehicle (EV) ownership, as well as investigate potential unknowns associated with EV charging, several utilities have initiated electric vehicle pilot programs, either as independent programs or as part of rate case settlement agreements. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Examples include: FPL's EVolution pilot program, DEF's Charge FL pilot program, and TECO's Drive Smart pilot program.

Some utilities, such as FPL and DEF, have begun to report key findings and metrics obtained through their respective EV pilot programs. This information includes: individual charging session data, peak EV charging hours, impacts to peak demand, as well as other metrics such as, revenue generated and port installation costs. Other utilities' EV pilot programs have not yet reached an age of maturity that will yield these same key findings. The Commission will continue to ask utilities to note key findings and track metrics of interest within these pilot programs in an effort to help inform the Commission about the future power needs of electric vehicles in Florida, which may require additional generating resources to meet their needs.

Conclusion

The Commission has reviewed the 2022 Ten-Year Site Plans of Florida's electric utilities and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity. The Commission will continue to monitor the impact of current and proposed EPA Rules, expansion of EV adoption, and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2022 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.

Introduction

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

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

Statutory Authority

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

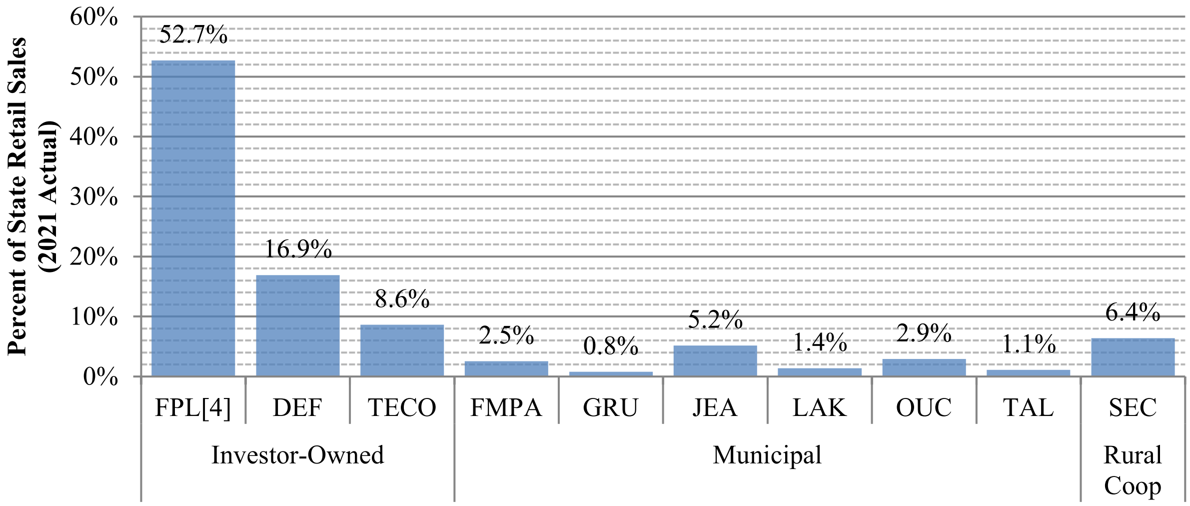
Applicable Utilities

Florida is served by 56 electric utilities, including 4 investor-owned utilities, 34 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 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 2022, 10 utilities met these requirements and filed a Ten-Year Site Plan, including 3 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. The municipal utilities, in alphabetical order, are Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. The sole rural electric cooperative filing a 2022 Ten-Year Site Plan is Seminole Electric Cooperative. 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 2021. Collectively, the reporting investor-owned utilities account for approximately 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 Sales



Source: FRCC 2022 Regional Load and Resource Plan & 2022 Ten-Year Site Plans

Required Content

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

Additional Resources

The Florida Reliability Coordinating Council (FRCC) compiles utility data 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

[4] FPL's value is the combined actual 2021 value of FPL and Gulf Power Company, which merged in 2022. Individually, FPL and Gulf Power Company represented 48.1 percent and 4.6 percent of the state's retail sales, respectively.

and reserves, and proposed new generating units and transmission line additions. For certain comparisons, the Commission employs additional data from various government agencies, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

On June 1, 2022 the Commission held a workshop regarding the annual planning process and the planning methodology for extreme winter events. Representatives from TECO, DEF, FPL, the Office of Public Counsel, Southern Alliance for Clean Energy, and Florida Rising each gave presentations. On July 11, 2022, FPL withdrew its Recommended Plan based on a novel extreme winter planning methodology and requested review of its Business As Usual Plan based on its traditional planning methodology.

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 10 reporting utilities' 2022 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.

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.

Statewide Perspective

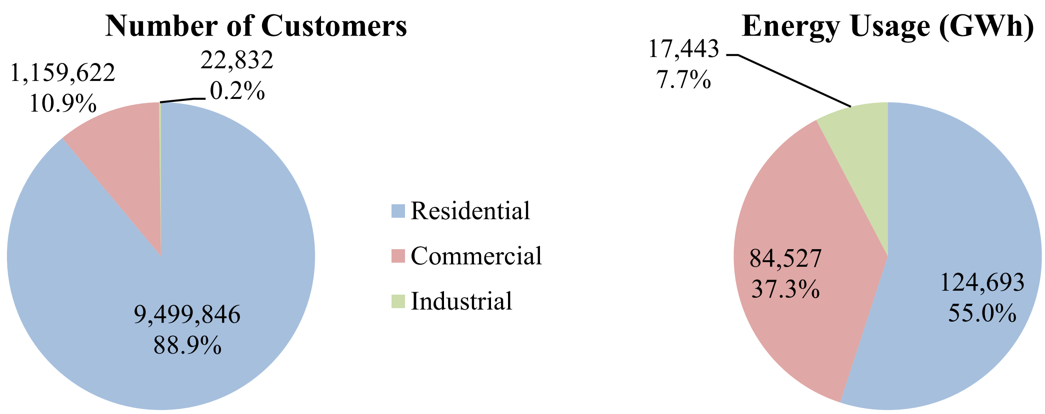
Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested forecasting methodologies, which are consistent with industrywide practices used in generation planning.

Electric Customer Composition

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2022, 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 2021



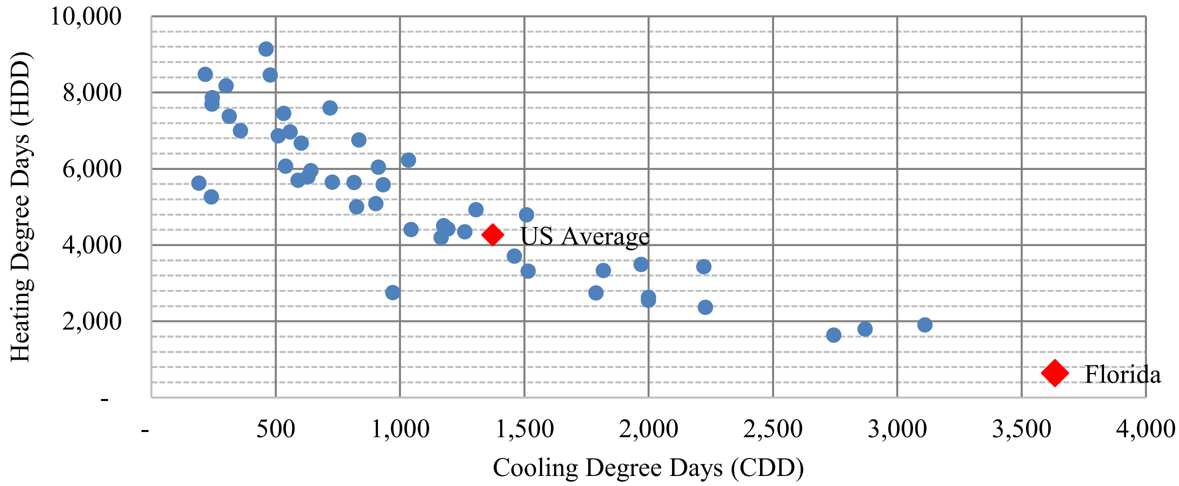
Source: FRCC 2022 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55 percent of retail energy sales in 2021, compared to a national average of approximately 39 percent.[5] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. 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. As such, most of Florida's utilities experience their peak demand during summer months. However, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels

[5] U.S. Energy Information Administration July 2022 Electric Power Monthly.

such as natural gas or oil for home heating needs. Even with the low frequency of heating days required, such reliance can impact winter peak demand.

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

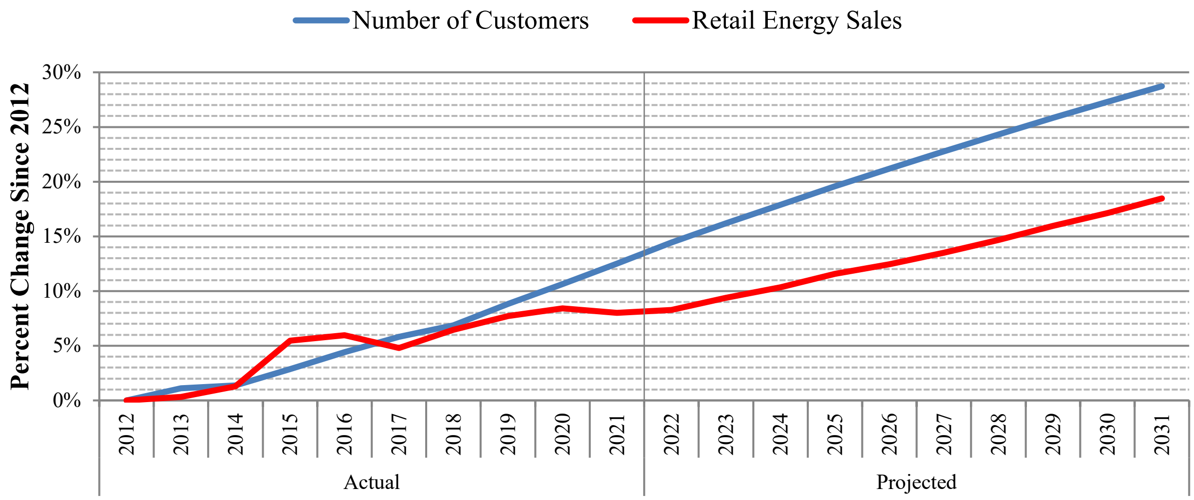


Source: National Oceanic and Atmospheric Administration Data

Growth Projections

For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.01 percent per year, compared to the 0.86 percent actual annual increase experienced during the 2012-2021 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.32 percent for the next 10-year period, the same as the actual annual increase experienced during the last decade. These trends are showcased in Figure 7.

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



Source: FRCC 2022 Regional Load and Resource Plan

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

With respect to the energy consumption per customer forecasts, FPL indicated that its residential use per customer will be flat or slightly decline through 2027 due to continued improvements in equipment efficiencies; then is expected to grow by 0.4 to 1 percent from 2028 due to economic growth and increased adoption of electric vehicles. The utility also expects that its commercial use per customer will decline by 0.3 to 0.6 percent per year over the forecast horizon due to continued improvements to equipment efficiencies. DEF reported that its per customer usage for both residential and commercial classes are primarily driven by fluctuations in electric price, end-use appliance saturation and efficiency improvement, building codes, and housing type/building size. In addition, the utility is aware that more recently, the customer's ability to self-generate has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generators, reducing energy consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind the meter. However, the utility also noted that the penetration of electric vehicles has grown, leading to an increase in residential use per customer, all else being equal. Each of these stated items is directly or indirectly incorporated in DEF's sales forecast. TECO echoed that increases in appliance/lighting efficiencies, energy efficiency of new homes, conservation efforts and housing mix are also the primary drivers affecting the decrease in per customer usage. Other TYSP utilities likewise reported that the downward pressure to the growth trend in per customer energy consumption is due to advancements in efficient technologies, renewable generation, and alternative energy sources, with some utilities expecting that the increased electric vehicle charging will mitigate this downward pressure to some extent.

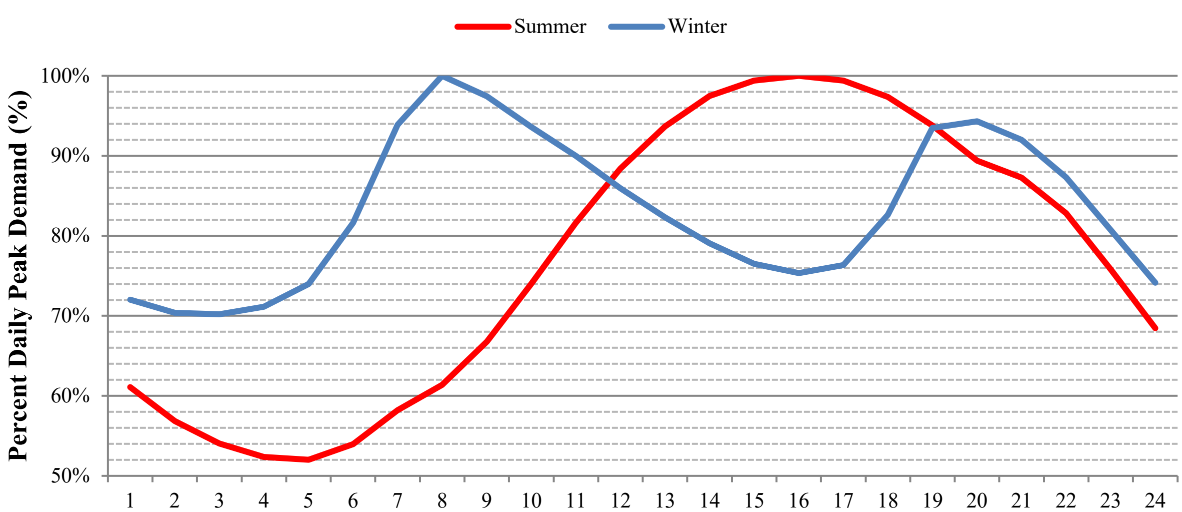
As shown in Figure 7, Florida utilities' total retail energy sales reached a historical peak in 2020. This is largely attributable to the significantly increased residential energy sales experienced by all of the utilities resulting from more people working and/or schooling from home due to the COVID-19 Pandemic. In 2021, the historical trend of Florida utilities' total retail energy sales experienced its second highest peak. As the aforementioned, Florida utilities' total retail energy sales are projected to grow at a higher annual average rate for the next 10 years than what was projected in the 2021 TYSPs. This sales growth is driven by growth in customers and business activity, as well as the expected increased level of adoption of electric vehicles.

Peak Demand

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

Seasonal weather patterns are a primary factor, with peak demands calculated separately for the summer and winter periods annually. The influence of residential customers is evident in the determination of these seasonal peaks, as they correspond to times of increased usage to meet home cooling (summer) and heating (winter) 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 spike in the morning and an additional spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

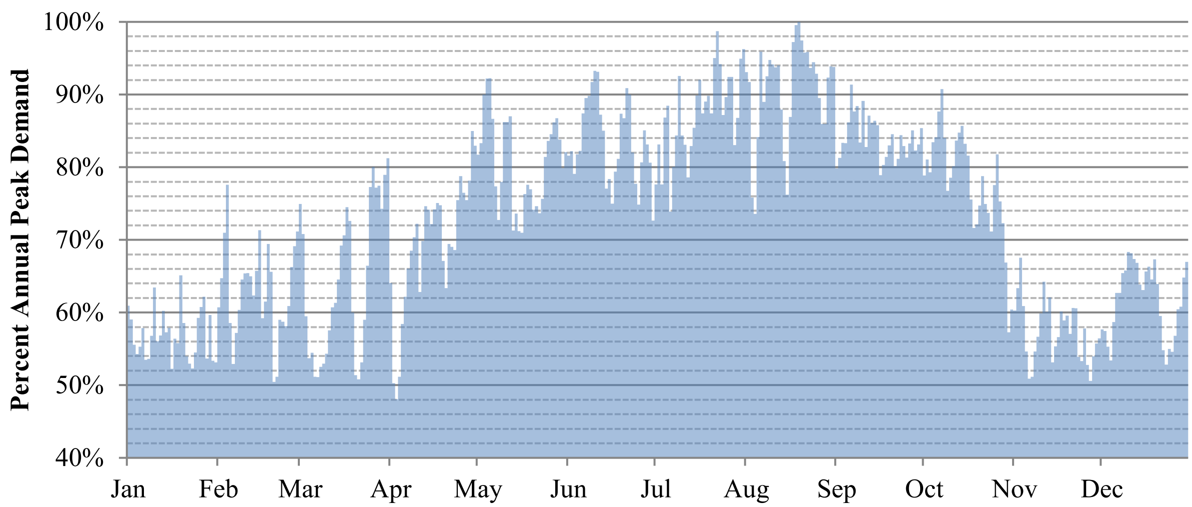


Source: TYSP Utilities' Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 shows the 2021 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 annual 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 (2021 Actual)



Source: 2022 TYSP Utilities' Data Responses (Investor-Owned Utilities Only)

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

Electric Vehicles

Utilities also examine other trends that may impact customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles. The reporting electric utilities estimate approximately 168,722 EVs will be operating in Florida by the end of 2022. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 9, 2022 at 18.07 million vehicles, resulting in an approximate 0.93 percent penetration rate of electric vehicles. Each of the TYSP Utilities was sent a data request regarding estimates of electric vehicle ownership, public charging stations, and impacts to their electric grid. All responded and provided projections except for FMPA, LAK, OUC, and SEC. LAK was able to provide estimates for the number of vehicles and chargers in 2022, but did not have projections for the planning period and estimated EV impacts were insignificant to its grid. OUC did not provide a forecast, with OUC citing uncertainty in the EV market. FMPA and SEC do not have service territories, but they do provide power to their member municipal utilities and rural electric cooperatives.

Florida's electric utilities anticipate continued 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 1,546,210 electric vehicles operating within the service territories of the TYSP Utilities by the end of 2031.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles

Year	FPL	DEF	TECO	JEA	GRU	LAK	TAL	Total
2022	116,202	33,325	12,218	4,220	1,065	534	1,158	168,722
2023	162,141	42,404	14,890	5,477	1,331	N/A	1,469	227,712
2024	220,697	52,918	17,742	6,939	1,664	N/A	1,832	301,792
2025	293,809	65,134	20,785	8,589	2,080	N/A	2,253	392,650
2026	391,240	79,267	24,119	10,419	2,600	N/A	2,736	510,381
2027	512,104	95,455	27,808	12,441	3,250	N/A	3,288	654,346
2028	657,776	114,021	31,977	14,689	4,063	N/A	3,921	826,447
2029	831,693	135,439	36,561	17,187	5,078	N/A	4,640	1,030,598
2030	1,037,328	160,059	41,599	19,951	6,348	N/A	5,459	1,270,744
2031	1,273,609	188,139	47,156	22,993	7,935	N/A	6,378	1,546,210

Source: TYSP Utilities' Data Responses

The major drivers of electric vehicle growth include a combination of the following: increased availability of charging infrastructure, lower fuel costs and emissions, increased commitment from auto manufacturers, broadened public outreach, expanded vehicle availability (makes and models), and strong government policy support at the local, state, and federal levels. Resulting from such policy support is the EV Infrastructure Master Plan, published in July 2021, in which the Florida Legislature required the Commission and the State Energy Office to assist the Florida Department of Transportation in developing and recommending a master plan for the development of electric vehicle charging station infrastructure along the Florida State Highway System.[6] Government agencies, private entities, municipalities, and electric utilities continue to work together to expand charging infrastructure throughout the state to meet this expected growth in electric vehicles as well as to promote electric vehicle ownership.

Table 3 illustrates the reporting electric utilities' projections of public EV charging stations through 2031. While approximately 6,000 charging stations are estimated to be available across the state by the end of 2022, more than 32,000 charging stations are anticipated by 2031. The

[6] Florida Department of Transportation, *EV Infrastructure Master Plan,* published July 2021.

estimated public EV charging station counts listed in Table 3 include both normal and "quick-charge" public charging stations.[7]

Table 3: TYSP Utilities - Estimated Number of Public EV Charging Stations

Year	FPL	DEF	TECO	JEA	GRU	LAK	TAL	Total
2022	4,646	573	461	110	85	19	88	5,982
2023	6,292	926	512	124	94	N/A	90	8,038
2024	5,535	1,438	562	139	103	N/A	92	7,869
2025	10,431	2,128	613	155	113	N/A	94	13,534
2026	10,802	3,035	664	172	124	N/A	96	14,893
2027	12,678	4,170	714	190	137	N/A	98	17,987
2028	14,681	5,459	765	209	151	N/A	100	21,365
2029	17,063	6,867	815	229	166	N/A	103	25,243
2030	18,700	8,382	866	251	182	N/A	106	28,487
2031	20,908	10,018	917	274	200	N/A	109	32,426

Source: TYSP Utilities' Data Responses

Table 4 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2031. Across the TYSP Utilities, anticipated growth would result in an annual energy consumption of 5,977.1 GWh by 2031, which represents an impact of approximately 2.2 percent of the projected net energy for load.

Table 4: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	231.0	24.0	34.6	17.2	3.8	3.5	314.2
2023	401.0	54.1	45.5	24.1	4.8	4.5	534.0
2024	623.0	91.9	57.3	32.1	6.0	5.6	816.0
2025	908.0	138.9	70.3	41.2	7.5	6.9	1,172.7
2026	1,289.0	199.0	84.6	51.2	9.4	8.4	1,641.6
2027	1,771.0	274.5	100.8	62.3	11.7	10.1	2,230.5
2028	2,361.0	366.8	118.3	74.7	14.6	12.1	2,947.6
2029	3,075.0	470.4	137.9	88.5	18.3	14.4	3,804.4
2030	3,930.0	586.2	159.5	103.7	22.9	17.0	4,819.2
2031	4,913.0	712.2	183.0	120.5	28.6	19.9	5,977.1

Source: TYSP Utilities' Data Responses

Table 5 illustrates the TYSP Utilities' estimates of the effects of electric vehicle ownership on summer and winter peak demand through 2031. Across the TYSP Utilities, anticipated growth results in an impact to summer peak demand of approximately 1,395 MW and an impact to winter peak demand of approximately 610 MW by 2031. Current estimates represent a cumulative impact

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

of approximately 2.6 percent on summer peak demand and a 1.2 percent on winter peak demand by 2031.

Table 5: TYSP Utilities – Estimated Electric Vehicle Impact – Seasonal Peak Demand

Summer Peak Demand (MW)

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	34	1.45	26.6	2.67	2.7	0.75	68
2023	76	3.6	31.7	3.73	3.3	0.95	119
2024	131	6.6	37.1	4.97	4.2	1.19	185
2025	202	10.5	42.8	6.37	5.2	1.46	268
2026	297	15.3	48.9	7.93	6.5	1.77	377
2027	418	21.2	55.6	9.65	8.1	2.13	515
2028	565	28.1	63.0	11.57	10.2	2.54	680
2029	744	71.0	71.0	18.33	12.7	3.00	920
2030	958	44.6	79.7	21.48	15.9	3.53	1,123
2031	1203	54.0	89.2	24.96	19.8	4.13	1,395

Winter Peak Demand (MW)

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	15	0.5	11.5	0.24	4.0	0.44	32
2023	33	1.3	13.9	0.34	5.0	0.55	54
2024	57	1.9	16.4	0.45	6.2	0.69	83
2025	87	2.7	19.0	0.57	7.8	0.85	118
2026	129	3.8	21.9	0.71	9.8	1.03	166
2027	181	5.3	25.0	0.87	12.2	1.24	226
2028	244	7.2	28.5	1.04	15.2	1.48	297
2029	322	9.5	32.4	1.23	19.0	1.75	386
2030	414	12.1	36.5	1.45	23.8	2.05	490
2031	520	14.8	41.0	1.68	29.8	2.40	610

Source: TYSP Utilities' Data Responses

Some utilities, such as FPL and DEF, have begun to report key findings and metrics obtained through their respective EV pilot programs. This information includes: individual charging session data, peak EV charging hours, impacts to peak demand, as well as other metrics such as revenue generated and port installation costs. Other utilities' EV pilot programs have not yet reached an age of maturity that will yield these same key findings. The Commission will continue to ask utilities to note key findings and track metrics of interest within these pilot programs in an effort to help inform the Commission about the future power needs of electric vehicles in Florida, which may require additional generating resources to meet their needs.

Demand-Side Management (DSM)

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

In 1980, the Florida Legislature established FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, known as the FEECA Utilities.[8] Of the TYSP Utilities, these include the three investor-owned electric utilities, FPL, DEF, TECO, and two municipal electric utilities, JEA and OUC. The FEECA Utilities represented approximately 86 percent of 2021 retail electric sales in Florida.

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

The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024. The Commission found that it was in the public interest to continue with the goals established in the 2014 FEECA goal-setting proceeding. Each FEECA electric utility was required to submit a proposed DSM Plan, designed to meet the goals within 90 days of the final order establishing the goals. In 2020, the Commission approved the DSM Plans proposed by the FEECA electric utilities. All FEECA Utilities that filed a 2022 Ten-Year Site Plan incorporated in their planning the impacts of the established DSM goals through 2024.

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

[8] FEECA also applies to Florida Public Utilities Company, a non-generating investor-owned electric utility. As FPUC purchases power from other generating entities and does not own or operate its own generation resources, it is not required to file a Ten-Year Site Plan. Based on its 2022 Annual Report, FPUC accounted for 0.3 percent of the State's retail energy sales in 2021.

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 2022, the total amount of demand response resources available for reduction of peak load is 3,097 MW for summer peak and 2,927 MW for winter peak. Demand response is anticipated to increase to approximately 3,401 MW for summer peak and 3,282 MW for winter peak by 2031.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of December 31, 2021, energy efficiency is responsible for peak load reductions of 4,669 MW for summer peak and 4,920 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,378 MW for summer peak and 5,296 MW for winter peak by 2031.

Forecast Load & Peak Demand

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

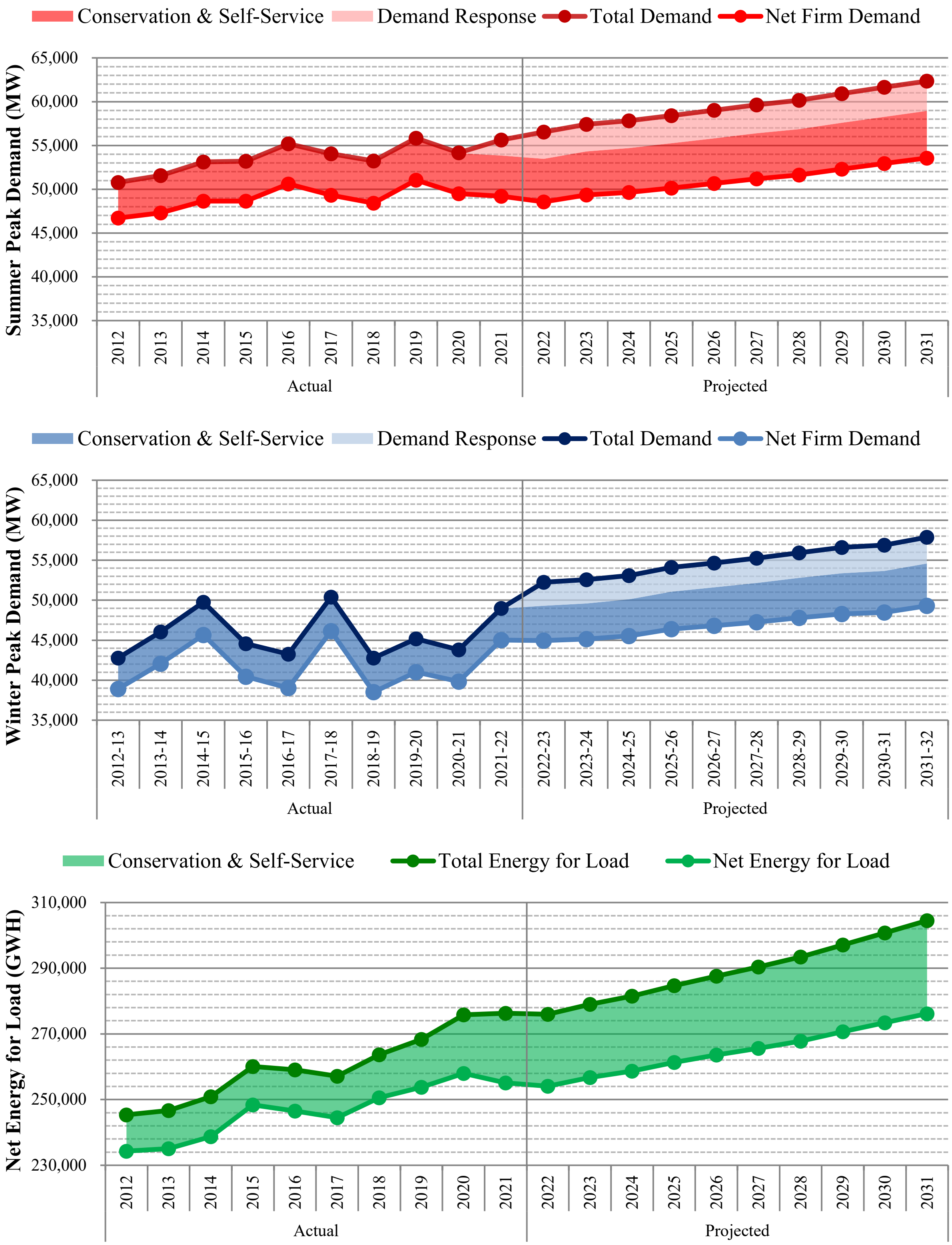
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served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

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

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

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

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



Source: FRCC 2022 Regional Load and Resource Plan

Forecast Methodology

Load forecasting is an essential requirement of all electric utility companies for purposes of system planning. In order for utilities to reliably and cost-effectively serve their respective customers, they must be able to accurately determine their energy and demand requirements. Thus, the load forecast function facilitates the ongoing equilibrium between system demand and system supply. Load forecasting can be divided into three types depending on the forecasting horizon: short, medium and long-term. Short-term load forecasting denotes forecast horizons of up to one week ahead. Medium-term load forecasting ranges from one week to one year ahead. Long-term load forecasting typically targets forecast horizons of one to ten years, and sometimes up to several decades. Long-term load forecasting provides the essential load requirement data that a utility must have in order to effectively modify its system of generation, transmission, and distribution assets. Load forecasts directly impact the timing, type, and location of expansions, replacements, and retirements. Hence, the load forecast function plays a vital role in an electric utility's system planning and, in Florida, serves as the foundation of a utility's Ten-Year Site Plan.

Florida's electric utilities perform long-term 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., winter peak demand per customer, residential energy use per customer) and independent variables (e.g., daily minimum temperature, heating 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 electric vehicles and distributed generation.

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

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

Historically, 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 models have relied upon dependent and independent variable data to project energy and demand amounts that exist within a probabilistic range. 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. Again in 2022, Florida's electric utilities used these same types of models and techniques to prepare their forecasts.

Accuracy of Retail Energy Sales Forecast

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for our review involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2021 retail energy sales were compared to the forecasts made in 2016, 2017, and 2018. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy by applying a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast. For the 2022 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2017 through 2021 to forecasts made between 2012 and 2018. These are summarized in Table 6.

Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts
(Five-Year Rolling Average)

Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2013	2013 - 2009	2010 - 2004	16.27%	16.27%
2014	2014 - 2010	2011 - 2005	14.99%	14.99%
2015	2015 - 2011	2012 - 2006	12.55%	12.55%
2016	2016 - 2012	2013 - 2007	9.19%	9.19%
2017	2017 - 2013	2014 - 2008	6.07%	6.07%
2018	2018 - 2014	2015 - 2009	3.58%	3.58%
2019	2019 - 2015	2016 - 2010	2.26%	2.42%
2020	2020 - 2016	2017 - 2011	1.68%	2.12%
2021	2021 - 2017	2018 - 2012	1.10%	1.67%

Source: 2004-2022 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 7 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 a three to five-year period that was also used in the analysis in Table 6.

As displayed in Table 7, the utilities' retail energy sales forecasts show large positive error rates during the recession-impacted period 2010 through 2014. Starting in 2015, 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 2010-2014 sales forecasts. The last two years' four-year ahead forecasts and the last three years' three-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, most of the last three years' two-year ahead forecasts and one-year ahead forecasts render negative error rates as well. The positive error rate exceptions are the 2020 one-year ahead forecasts and 2021 two-year ahead forecasts which reflect the unforeseen impacts of the COVID-19 Pandemic-related shelter-in-place orders in 2020. The current TYSP also shows a very small error rate with respect to both average and absolute average three to five year error percentages. Likewise, the one-year ahead forecast error associated with the 2022 TYSPs appears to be one of the lowest since 2010.

Table 7: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2010	13.03%	15.68%	14.99%	13.81%	10.65%	-0.65%	14.83%	14.83%
2011	21.67%	20.91%	20.22%	17.14%	3.89%	0.18%	19.42%	19.42%
2012	26.43%	26.12%	23.16%	8.58%	4.01%	3.81%	19.29%	19.29%
2013	28.71%	26.42%	10.11%	6.09%	5.69%	3.08%	14.21%	14.21%
2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	7.21%	7.21%
2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	2.63%	2.63%
2016	4.33%	4.38%	2.28%	1.25%	0.20%	-0.97%	2.64%	2.64%
2017	6.99%	4.93%	3.59%	2.53%	1.57%	-0.07%	3.68%	3.68%
2018	4.28%	2.76%	1.76%	0.75%	-1.13%	-1.08%	1.76%	1.76%
2019	2.95%	2.04%	0.92%	-1.23%	-1.25%	-1.87%	0.58%	1.40%
2020	2.44%	1.27%	-0.97%	-1.07%	-1.91%	2.73%	-0.25%	1.10%
2021	2.47%	0.24%	-0.09%	-0.91%	3.80%	-0.08%	-0.26%	0.41%

Source: 2004-2022 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 2021 in Table 6. However, current major global and domestic events could, individually or collectively, inflict damage to the US economy. As such, there remains uncertainty as to when the economic impacts of these events will end. As a result, the actual retail energy sales of the next few years could be different from what Florida utilities projected in 2021 and prior years. Consequently, the average forecasted energy sales error rates in the next few years may deviate from the lower levels recently recorded. It is important to recognize that the dynamic nature of the economy, the weather, and now even global health, political and economic issues present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of energy sales forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., the Legislature has found that it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(e), 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 or resulting 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)(e), 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 7,584 MW of firm and non-firm generation capacity, which represents 9.2 percent of Florida's overall generation capacity of 63,895 MW in 2021. Table 8 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 8: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	6,085	80.2%
Municipal Solid Waste	451	5.9%
Biomass	380	5.0%
Waste Heat	276	3.6%
Wind	272	3.6%
Landfill Gas	70	0.9%
Hydroelectric	51	0.7%
Renewable Total	**7,584**	100.0%

Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the total 7,584 MW of renewable generation, approximately 2,790 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 2,458 MW to this total, based upon the coincidence of solar generation and summer peak demand, or about 40 percent of its installed capacity. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

Of the 1,499 MW of non-solar generation, only 332 MW is treated as firm because of contractual commitments. 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.

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 4,490 MW of existing utility-owned solar capacity, approximately 2,347 MW, or about 52 percent, is considered firm.

Non-Utility Renewable Generation

Approximately 2938 MW, or 39 percent of Florida's existing renewable capacity is from non-utility owned sources. A majority, approximately 1,761 MW, or 23 percent, comes from mostly municipal solid waste and solar facilities. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

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

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

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

Demand-Side Renewable Generation

Approximately 1,177 MW, or 16 percent of existing non-utility owned renewable generation is from customer-owned systems, also referred to as demand-side renewable systems. Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2021, approximately 1,177 MW of renewable capacity from over 130,947 systems has been installed statewide. Table 9 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 34 installations and 7.1 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 9: State of Florida - Customer-Owned Renewable Growth

Year	2014	2015	2016	2017	2018	2019	2020	2021
Number of Installations	8,581	11,626	15,994	24,166	37,862	59,508	90,552	103,947
Installed Capacity (MW)	79.8	107.5	141	205	317	514	835	1,177

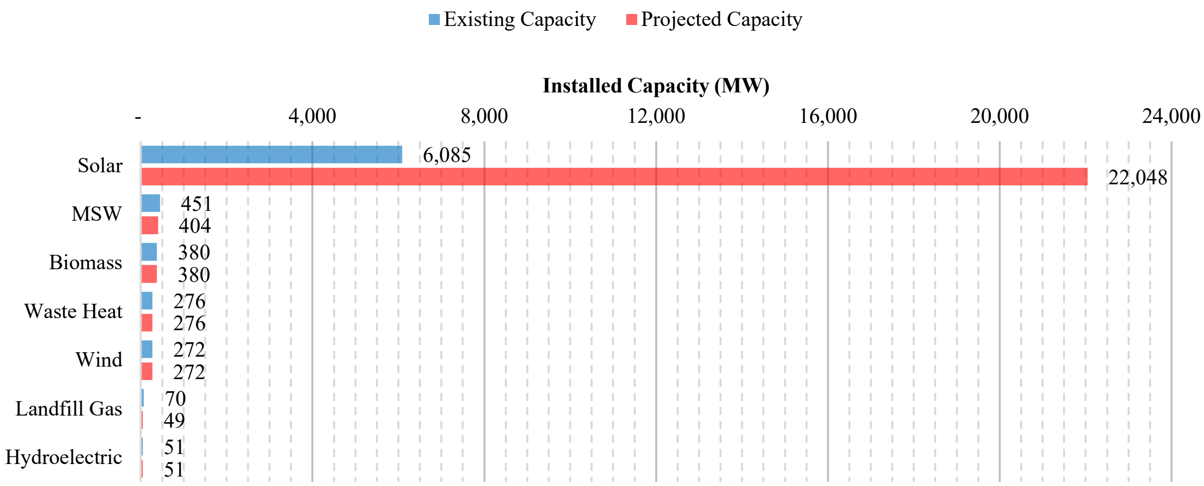
Source: 2015-2022 Net Metering Reports

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 15,894 MW over the 10-year planning period, an increase from last year's estimated 15,055 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type. Solar generation, primarily utility-owned, is projected to have the greatest increase over the planning horizon.

Of the 15,894 MW projected net increase in renewable capacity, firm resources contribute 5,279 MW, or about 33 percent, of the total. This net increase value takes into account that for some existing renewable facilities contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

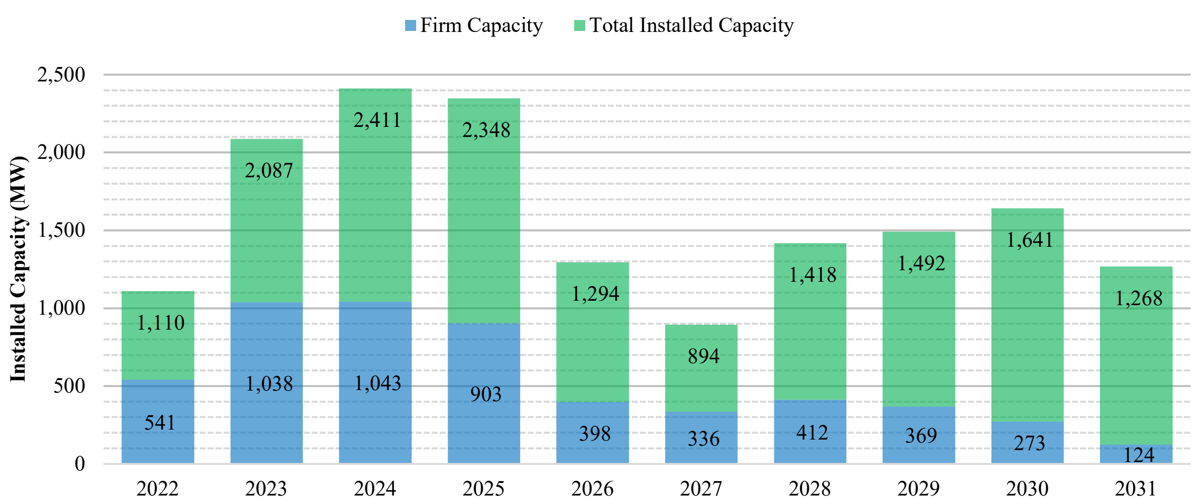
Figure 11: State of Florida - Current and Projected Renewable Resources



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 15,963 MW to be installed. This consists of 13,650 MW of utility-owned solar and 2,313 MW of contracted solar. The firm contribution of solar varies by utility, with some having a set percentage value for all projects over the planning period, and others having a declining value as projects are added. Figure 12 provides an overview of the additional solar capacity generation planned within the next 10 years, as well as the amount considered firm for summer reserve margin planning.

Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Energy Storage Outlook

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

As part of its 2016 Settlement, FPL deployed approximately 50 MW of non-firm capacity through its Battery Storage Pilot Program, which examines the applications of combining battery storage with new and existing solar facilities.[9] In 2021, FPL added 409 MW of battery storage in Manatee County, which is charged by an existing PV facility. Additionally, two other 30 MW battery storage facilities were installed at two different locations and put into service in 2021. FPL's 2022 TYSP includes an additional 1,800 MW of unsited solar charged battery storage additions over the next 10 years.

DEF is expanding its battery storage with a 50 MW, non-firm capacity, Battery Storage Pilot Program as part of its 2017 Settlement.[10] The program includes six solar charged battery energy storage systems. Trenton and Lake Placid battery energy storage systems were placed in-service in late 2021 with the remaining four battery energy storage systems under construction and expected to be placed in-service in 2022. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages. DEF will use the data gathered from the operation of these systems to evaluate future opportunities with battery storage. DEF is planning an additional 111 MW of solar connected battery storage by the end of 2031.

TECO installed a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility is interconnected with the solar array and is expected to add 5.6 MW of firm capacity. In 2021 TECO completed its first integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries which re-charge the Company's EV fleet. Over the next 10 years, TECO expects to deploy approximately 265 MW of energy storage systems to meet system reliability needs, maximize solar energy production, and to avoid transmission and distribution investments.

In addition to utility-owned battery storage, energy storage associated with purchased power agreements are also anticipated in the planning horizon. OUC also plans to enter into purchased power agreements with energy storage providers connected to future solar facilities, with an estimated 350 MW of capacity through 2031. Overall, whether utility-owned or contracted, a total of 2,819 MW of battery storage is projected to be installed by 2031.

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[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.*

Traditional Generation

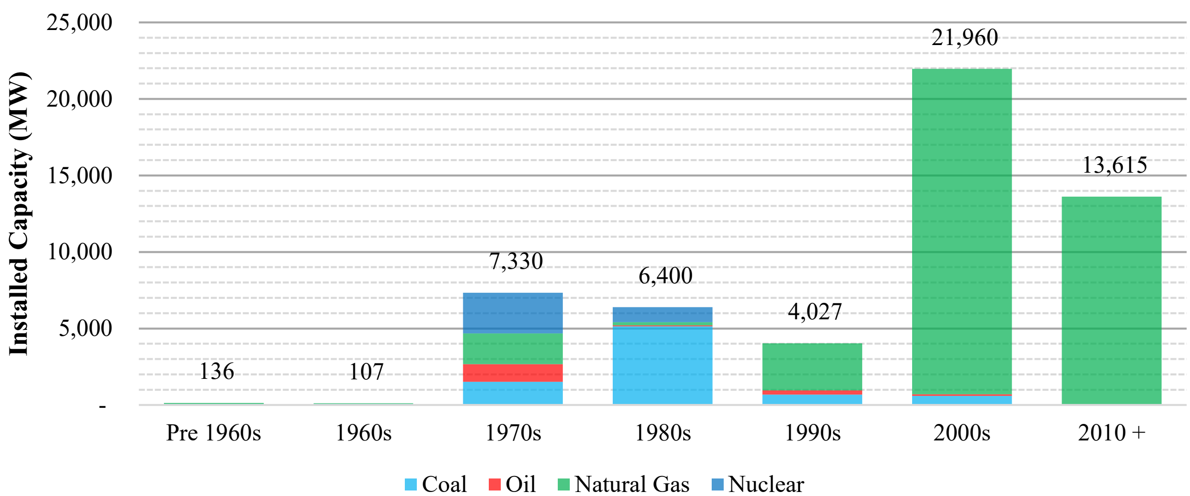
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. 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 50 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 13 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

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



Source: FRCC 2022 Regional Load and Resource Plan

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

Impact of EPA Rules

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, the six EPA rules identified below were anticipated to affect electric generation in Florida. The first five rules are currently under EPA review pursuant to Executive Order 13990. [11] Future developments will be addressed in a subsequent Ten-Year Site Plan review.

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

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

[11] See Executive Order 13990 Fact Sheet.

- Prevention of Significant Deterioration and Nonattachment New Source Review: On August 1, 2019, the EPA announced a proposed rule that would revise certain New Source 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 - Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.

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

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

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

Modernization and Efficiency Improvements

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

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

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. TECO is modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by the end of 2022. 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 10 lists the 4,003 MW of existing generation that is scheduled to be retired during the planning period. A majority of the retirements are coal-fired steam generators, with 10 units totaling 3,400 MW of capacity to be retired by 2031. Additional capacity reductions in coal occur due to fuel switching, such as the approximately 464 MW Stanton Unit 2, jointly owned by FMPA and OUC, which will be converted to natural gas in 2027.

Table 10: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW) Summer
Coal Steam Retirements			
2022	FPL & JEA	Scherer Unit 4	832
2022	SEC	Seminole Generating Station Unit 1	626
2023	TEC	Big Bend Unit 3	395
2024	FPL	Daniel Units 1 & 2	502
2025	FPL	Gulf CEC Units 4 & 5	150
2025	FMPA & OUC	Stanton Unit 1	452
2029	FPL	Scherer Unit 3	215
2031	GRU	Deerhaven Unit FS02	228
		Coal Subtotal	**3,400**
Oil Combustion Turbine Retirements			
2025	FPL	Lansing Smith Unit A	32
2025	DEF	Bayboro Units P1-P4	171
2027	DEF	Debary Units P2-P6	227
2027	DEF	P.L. Bartow Units P1 & P3	82
		Oil Subtotal	**512**
Natural Gas Combustion Turbine Retirements			
2025	FPL	Pea Ridge Units 1-3	12
2026	GRU	Deerhaven Units GT01-02	35
2027	DEF	University of Florida Unit P1	44
		Gas Subtotal	**91**
		Total Retirements	**4,003**

Source: 2022 Ten-Year Site Plans

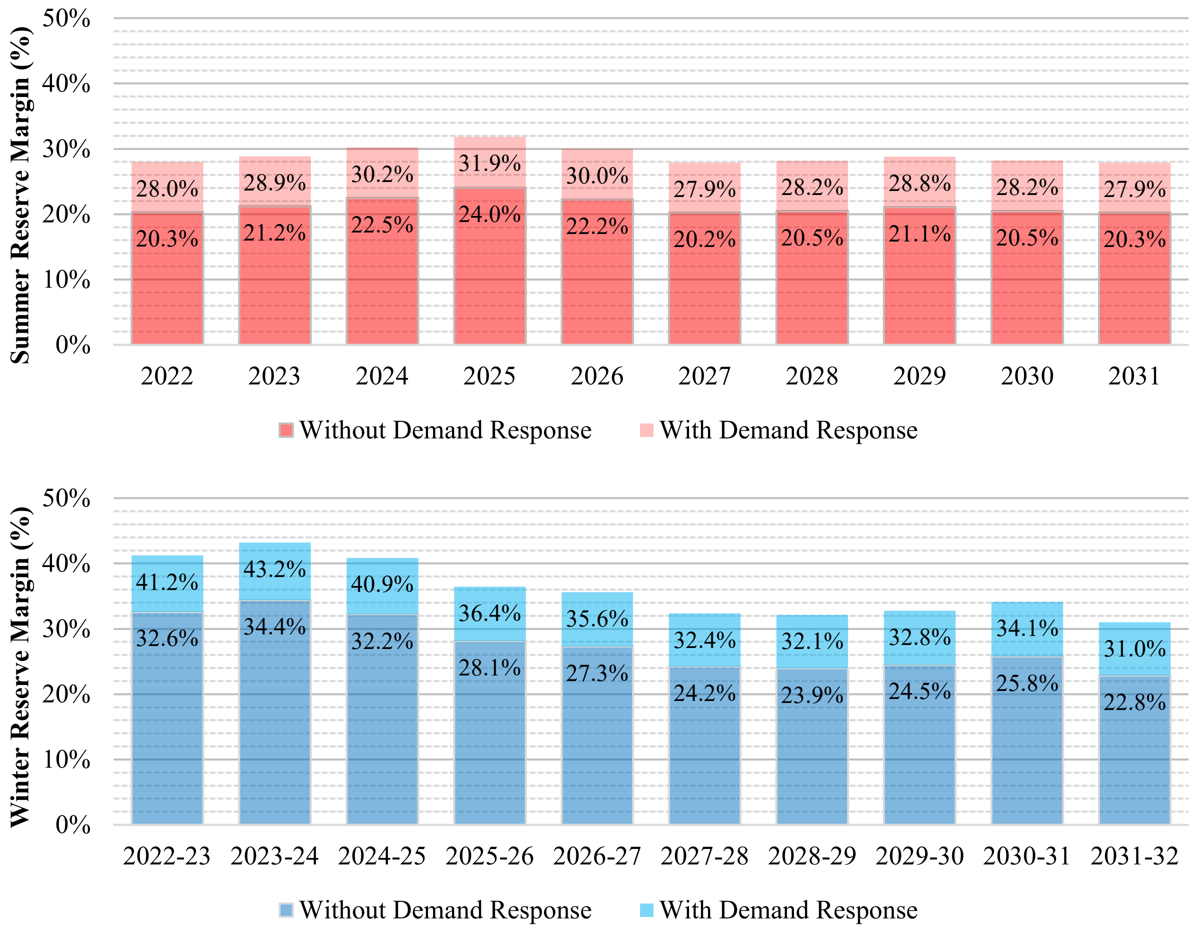
Reliability Requirements

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

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

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



Source: FRCC 2022 Regional Load and Resource Plan - Revised Form 10

Role of Demand Response in Reserve Margin

The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 14, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin on average 7.7 percent in summer and 8.4 percent in winter.

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

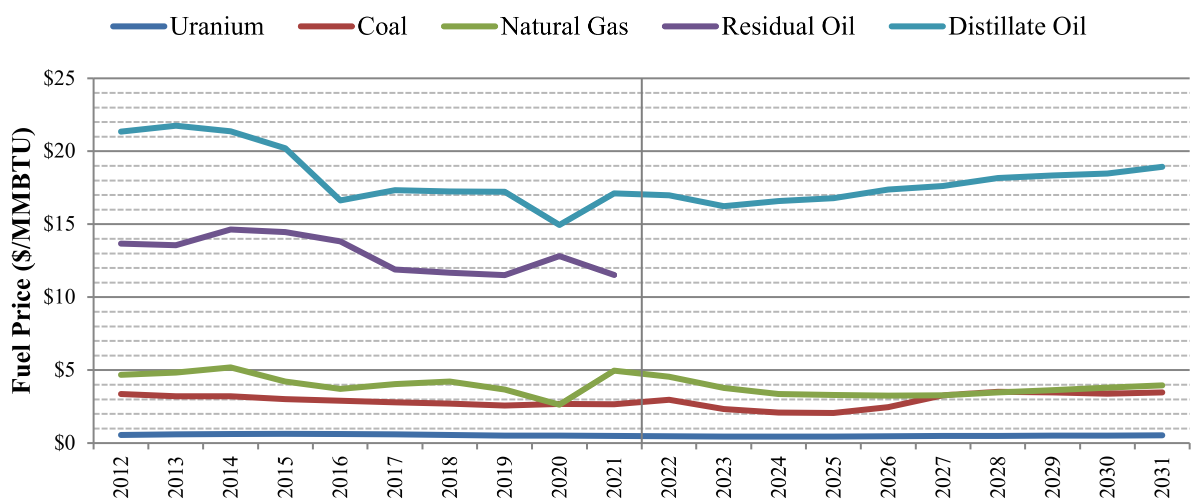
Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a fuel-based power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, and uranium. Distillate oil also factors into Florida utilities' fuel mix, albeit minimally when compared to historical levels. Figure 15 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

Natural gas remains the most intensively used fuel state-wide on a per GWh basis, accounting for 69.15 percent of electric generation in 2021.[12] As shown in Figure 15, the price of natural gas continued to decline from 2012 until 2020. However, there was an 89 percent increase, from a unit price in dollars per million British Thermal Units (BTUs) of $2.63 in 2020 to $4.97 in 2021. The price of natural gas is now forecast to decline from 2021 through 2026. Meanwhile, the price of coal has been stable from 2012 through 2021. However, forecasts show a slight decrease through 2025 at which time it is forecast to increase by roughly 68 percent from 2025 through 2031. It should be noted that the use of coal is projected to decrease substantially over the next 10 years.

Distillate oil remains the most expensive fuel, which explains why it is used for backup and peaking purposes only. Also of note is a phasing out of residual oil, with no forecast for purchasing residual oil after 2021. The truncated graph on Figure 15 reflects this phasing out of residual oil.

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



Source: TYSP Utilities' Data Responses

As shown in Figure 15, the price of natural gas continued to decline from 2012 until 2020. Even though current forecasts project the price of natural gas to remain relatively stable over the long term, there remains some degree of natural gas price volatility over the short and medium term.

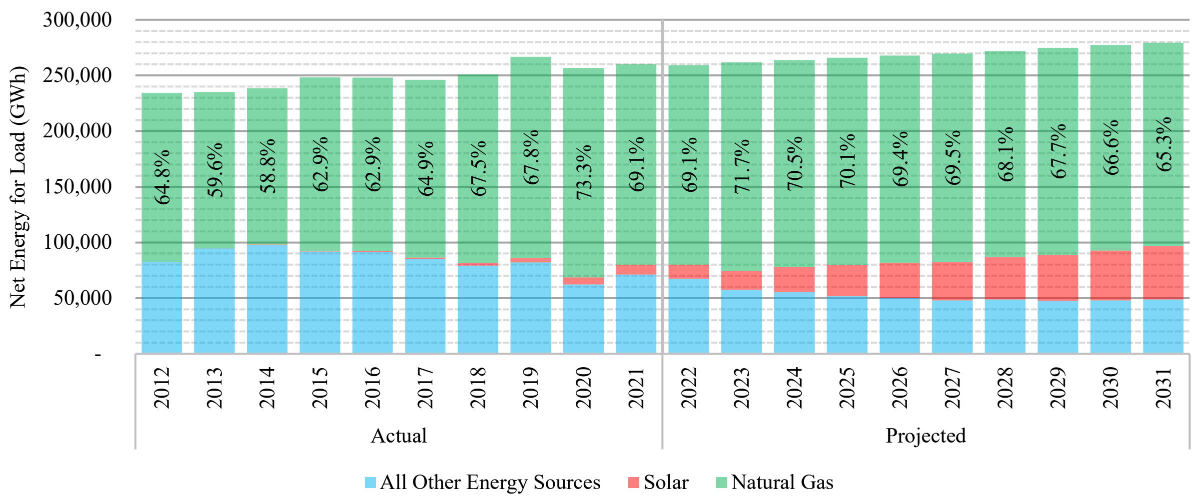
[12] 2022 Florida Reliability Coordinating Council 2022 Regional Load and Resource Plan, p. S-19.

For instance, natural gas price volatility was reflected in the 2021 requests for fuel factor mid-course corrections (increases in customer fuel charges) filed by TECO and DEF, and approved by the Commission on August 30, 2021.[13]

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida and since 2011 has generated more net energy for load than all other fuels combined. As Figure 16 illustrates, natural gas was the source of approximately 69 percent of electric energy consumed in Florida in 2021. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline slightly throughout the remainder of the planning period.

Figure 16: State of Florida - Natural Gas Generation



Source: FRCC 2013-2022 Regional Load and Resource Plans

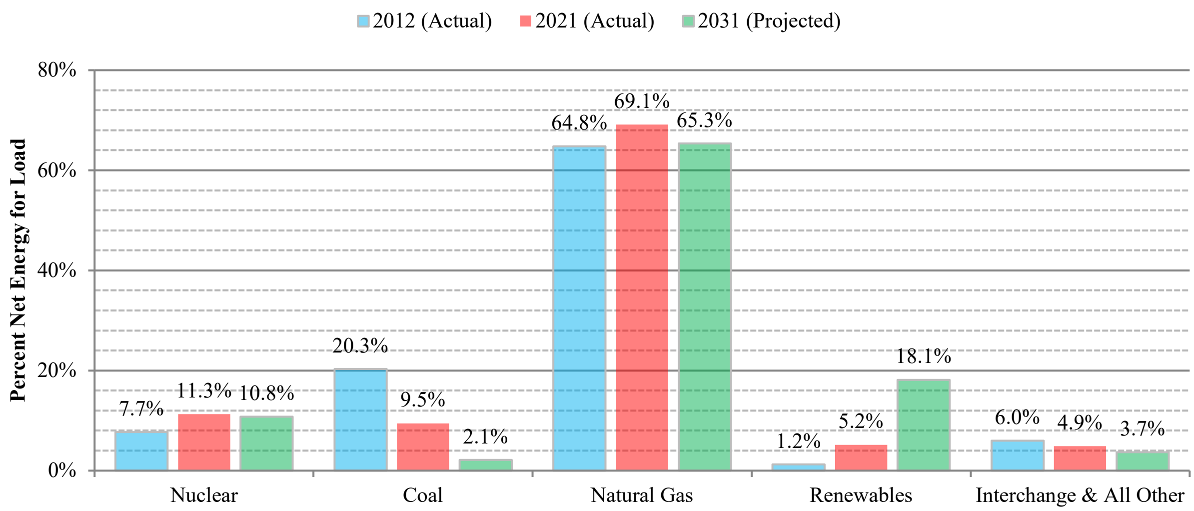
Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatility in fuel price fluctuations, it is important that utilities have a level of flexibility in their generation mix. Maintaining fuel diversity on Florida's system faces several difficulties. Existing coal 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 17 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2012 and 2021, and forecast year 2031. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of

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

energy consumption, and this trend is anticipated to continue throughout the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2031.

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



Source: FRCC 2013-2022 Regional Load and Resource Plan

Based on 2020 Energy Information Administration data, Florida ranks fifth 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. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

New Generation Planned

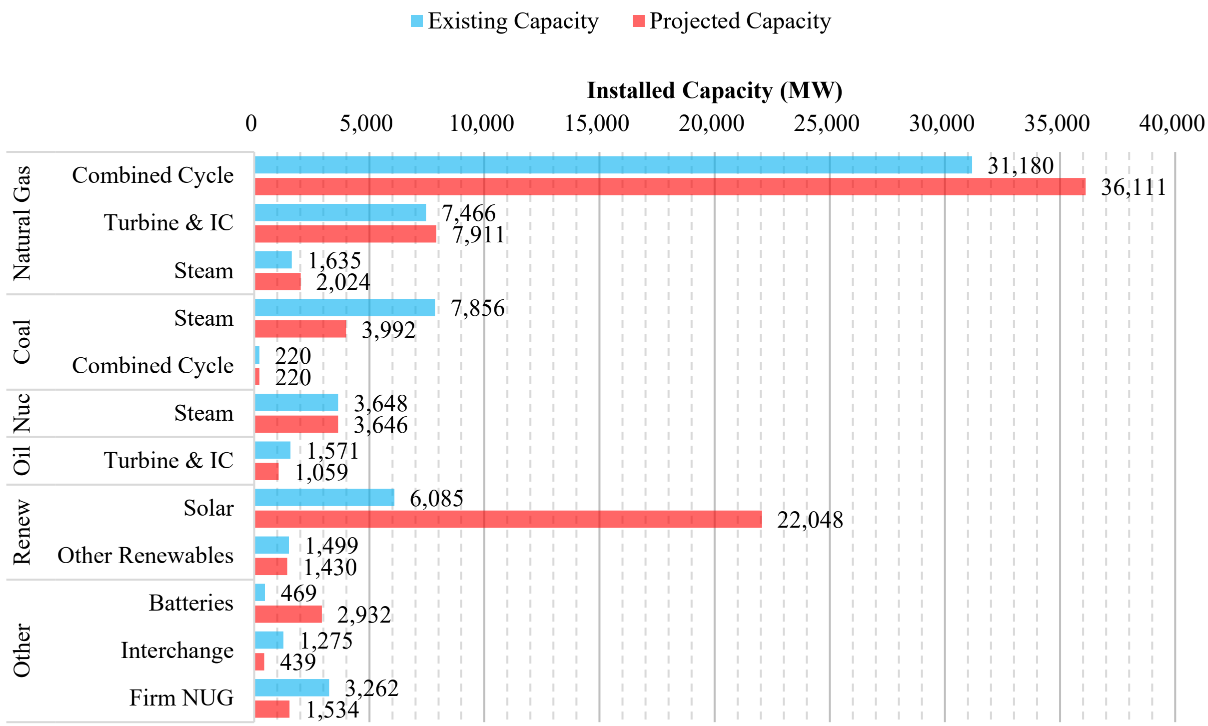
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity is expected to increase, making the addition of traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.
In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water

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

supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

Figure 18 illustrates the present and future aggregate capacity mix. The capacity values in Figure 18 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2022 Ten-Year Site Plans and the FRCC's 2022 Regional Load and Resource Plan.

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



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

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. Only one planned unit requires certification under the PPSA, a 571 MW natural gas-fired combined cycle with an in-service date in 2025 for SEC.

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 2018, FPL received Combined Operating Licenses from the Nuclear Regulatory Commission for two future nuclear units, Turkey Point Units 6 & 7. These units are planned to be sited at FPL's Turkey Point site, the location of two existing nuclear generating units. The earliest possible in service date for these two units are outside the scope of the Ten-Year Site Plan.

Natural Gas

Several new natural gas-fired combustion turbines, internal combustion units, and combined cycle units are planned over the next 10 years. While combined cycle systems are the dominant generating unit type, combustion turbines that run only in simple cycle mode and internal combustion units, taken together, will represent the third most abundant type of generating capacity by the end of 2031. 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 11 summarizes the approximately 4,048 MW of additional capacity from new natural gas-fired generating units proposed by the 2022 Ten-Year Site Plan utilities.

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

Table 11: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
Previously Approved New PPSA Units					
2022	FPL	Dania Beach Energy Center	CC	1,258	Docket No. 20170225-EI
2022	SEC	Seminole CC Facility	CC	1,099	Docket No. 20170266-EI
			Subtotal	**2,357**	
New Units Requiring PPSA Approval					
2025	SEC	Unnamed CC	CC	571	
			Subtotal	**571**	
New Units Not Requiring PPSA Approval					
2023	TECO	Big Bend CC Conversion	CC	395	Incremental Capacity
2024	LAK	C.D. McIntosh, Jr Units 01-06	IC	120	Six 20 MW Units
2025	TECO	Reciprocating Engine	IC	37	Pair of 18.5 MW Units
2027	SEC	Unnamed Combustion Turbine	CT	317	
2028	TECO	Reciprocating Engine	IC	37	Pair of 18.5 MW Units
2029	DEF	Unsited Combustion Turbine	CT	214	
			Subtotal	**1,120**	
			Total	**4,048**	

Source: 2022 Ten-Year Site Plans

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 12 lists all proposed transmission lines in the 2022 Ten-Year Site Plans and the FRCC 2022 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 12: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Levee to Midway	150	500	5/28/1988	4/20/1990	2030
FPL	Sweatt to Whidden	79	230	6/03/2022	TBD	2025
TECO	Thonotosassa to Wheeler	8	230	6/22/2007	8/8/2008	TBD
TECO	Wheeler to Willow Oak	17	230	6/23/2006	8/9/2008	TBD
TECO	Lake Agnes to Gifford	28	230	9/26/2007	2/18/2009	TBD

Source: 2022 Ten-Year Site Plans & FRCC 2022 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. FPL's service territory previously was solely in the FRCC Region and consisted of South Florida and the east coast. In 2019, FPL's parent company, NextEra Energy Inc., acquired Gulf Power Company (GPC). GPC's service territory was in the Florida Panhandle region. While the companies merged at the beginning of 2022, it was not until mid-2022 that the companies transitioned into operating as a single entity with the completion of an interconnecting transmission line project, the North Florida Resiliency Connection. As a result, the 2022 Ten-Year Site Plan for FPL contains actual distinct data for the FPL and GPC regions through 2022, and combined data for projections through 2031.

In its 2022 Ten-Year Site Plan filing, FPL submitted four Ten-Year Site Plans for the Commission's consideration. These included a Business As Usual Plan, which used the Company's traditional resource planning methodology, its Recommended Plan, which introduced a novel extreme winter planning methodology, and two additional plans for informational purposes only that projected the potential impact of possible federal legislation as variations of the Business As Usual and Recommended Plans. In its original filing, FPL sought approval of its Recommended Plan. On July 11, 2022, FPL submitted a letter withdrawing its Recommended Plan and requesting approval of the Business As Usual Plan. Therefore, the analysis contained within this section and the Statewide Perspective address only the Business As Usual Plan.

As an investor-owned utility, FPL, is subject to the regulatory authority of the Commission over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL 2022 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2021, FPL legacy service area had approximately 5,214,263 customers and annual retail energy sales of 112,177 GWh, or approximately 47.9 percent of Florida's annual retail energy sales. GPC legacy service area had approximately 477,672 customers and annual retail energy sales of 10,731 GWh, or approximately 4.6 percent of Florida's 2021 annual retail energy sales. In both service areas, the total number of customers grew by approximately 1.5 percent in 2021 which was driven primarily by growth in the number of residential customers.

FPL's weather-normalized retail energy sales increased by 1.4 percent in 2021, driven by growth of the number of customers in the residential and commercial classes. Residential energy sales increased due to growth in the number of customers, even though the increase was partially offset by per customer usage declines. Commercial energy sales increased due to both customer numbers and per customer usage growth.

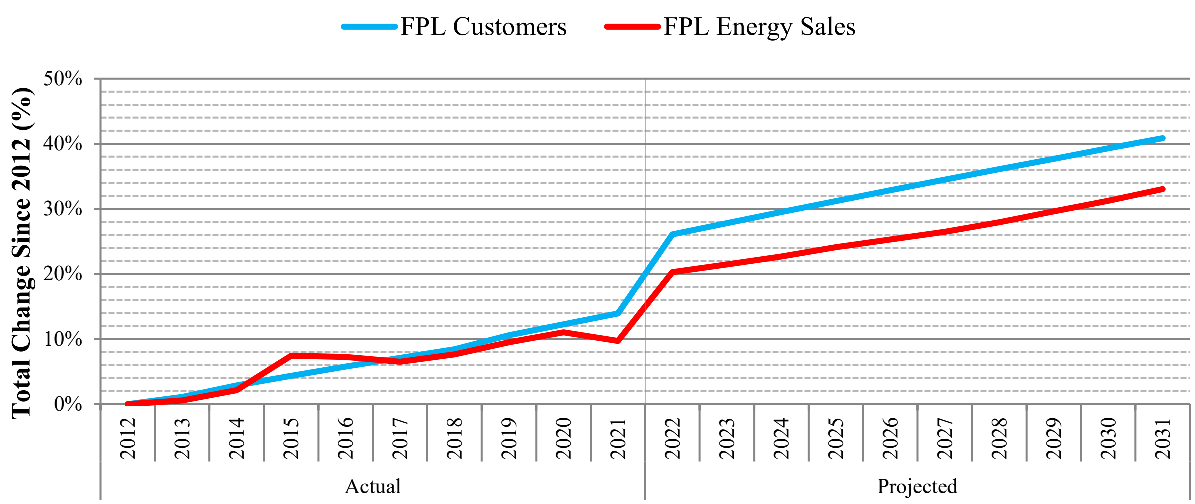
GPC's weather-normalized retail energy sales increased by 0.6 percent in 2021 due to higher commercial energy sales, partially offset by residential and industrial energy sales. Residential energy sales decreased due to usage declines, even though the increase was partially offset by growth in the number of customers. Industrial energy sales also decreased due to lower usage.

Over the past 10 years, FPL's customer base has increased by 13.9 percent, while retail sales have grown by approximately 9.7 percent. For the 2022 TYSP forecast horizon, the number of customers for the combined FPL and Gulf system are forecasted to grow by 1.1 to 1.4 percent per year. According to FPL, its total customer growth is being driven primarily by growth in residential customer numbers.

With respect to the average energy consumption per customer reflected in FPL's retail sales, residential use per customer for the combined system is forecasted to be flat or slightly decline through 2027 due to continued improvements in equipment efficiencies. For years 2028 and beyond, use per customer is forecasted to grow by 0.4 to 1.0 percent per year due to economic growth and increased adoption of electric vehicles. Commercial usage is forecasted to decline by 0.3 to 0.6 percent per year over the forecast horizon due to improvements to equipment efficiencies.

FPL's retail sales are forecasted to grow by 0.6 to 1.2 percent per year over the TYSP forecast horizon. This projected total retail sales growth is driven by sales growth in the residential class and commercial class, and these class-level energy sales increases are driven by growth in the number customers. Figure 19 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the two resource plans FPL filed in its 2022 TYSP.

Figure 19: FPL Growth
(Reflects post operational integration with GPC)



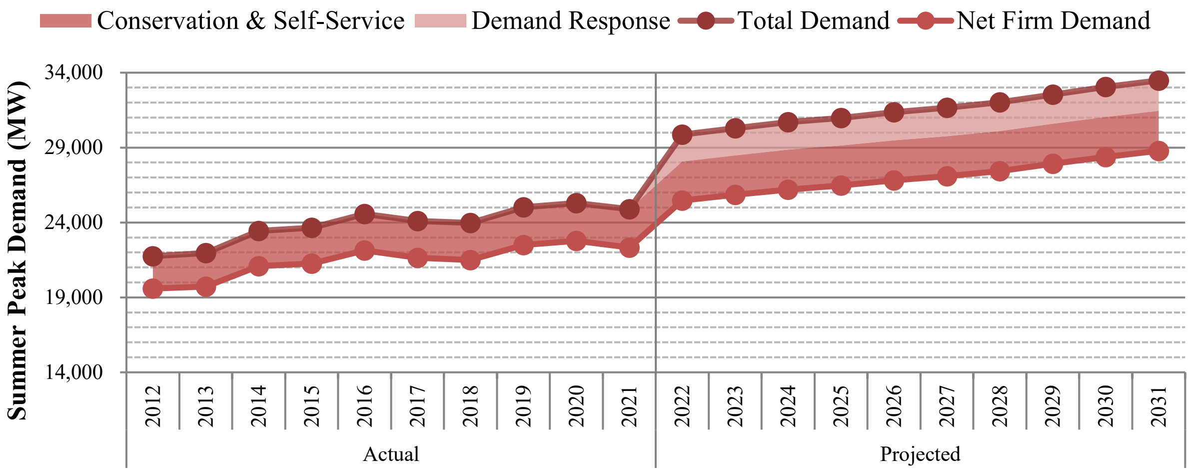
Source: 2022 Ten-Year Site Plan

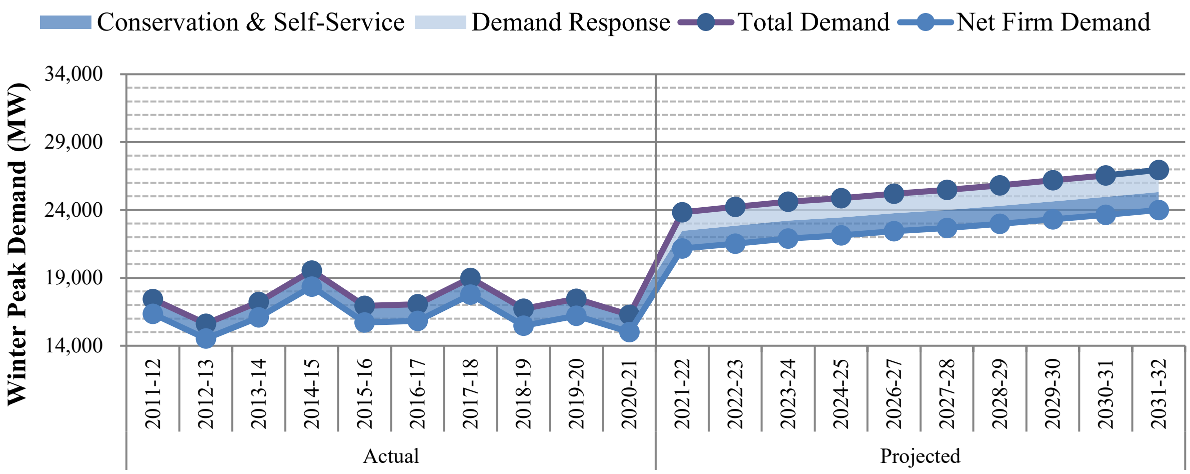
As mentioned earlier, on January 1, 2019, GPC became a subsidiary of NextEra, FPL's parent company. FPL and GPC integrated the two systems into a single electric system, effective January 1, 2022. Despite the fact that the FPL and GPC systems were not be interconnected until mid-2022, the demand and energy forecasts for the years 2022 through 2031 are presented as a single integrated utility (FPL), as depicted in Figure 20.

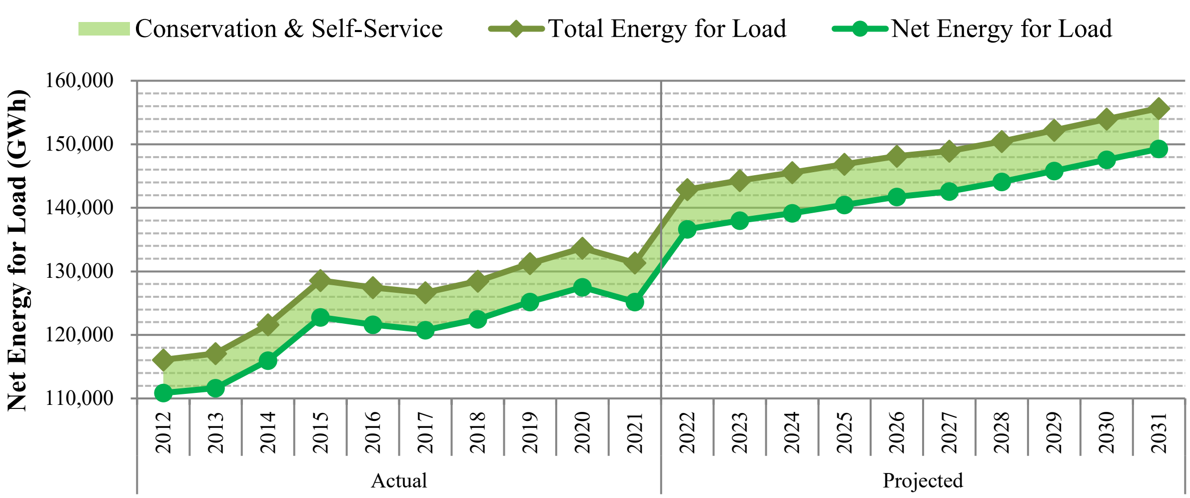
The three graphs in Figure 20 show FPL's seasonal peak demand, summer and winter, and net energy for load, for the historic years 2012 through 2021, with the integrated FPL/GPC forecast for years 2022 through 2031. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. FPL expects a spike in all demand and energy forecasts in 2022 due to its planned integration with GPC's system. During the past 10 years, demand response has not been activated during seasonal peak demand.

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. The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024. In August 2020, the Commission approved separate FPL and GPC DSM plans designed to achieve the 2020-2024 DSM goals. In November 2021, the Commission approved an integrated FPL DSM plan designed to achieve FPL's and GPC's goals combined. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, FPL/GPC assume the trends in these goals will be extended through the forecast period (through 2031).

Figure 20: FPL Demand and Energy Forecasts
(Reflects post operational integration with GPC)







Source: 2022 Ten-Year Site Plan

Fuel Diversity

Table 13 shows FPL's and GPC's actual net energy for load by fuel type for 2021 and the projected fuel mix for the combined companies for 2031. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 95 percent of net energy for load in 2021. GPC was an energy exporter in 2021, producing approximately 20 percent more energy than it required for native load. By 2031, the FPL system is projected to reduce natural gas usage from nearly 73 percent to approximately 61 percent. FPL projects that renewable energy will provide over 19 percent of its generation by 2031, which is the fifth highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 13: FPL and GPC Energy Generation by Fuel Type

Fuel Type	Net Energy for Load					
	FPL		GPC		FPL	
	2021		2021		2031	
	GWh	%	GWh	%	GWh	%
Natural Gas	90,903	**72.6%**	10,720	**92.5%**	90,484	**60.5%**
Coal	2,089	**1.7%**	1,765	**15.2%**	0	**0.0%**
Nuclear	28,342	**22.6%**	0	**0.0%**	28,919	**19.3%**
Oil	158	**0.1%**	0	**0.0%**	1	**0.0%**
Renewable	5,746	**4.6%**	1,441	**12.4%**	28,816	**19.3%**
Interchange	0	**0.0%**	-2,328	**-20.1%**	0	**0.0%**
Other	(2,071)	**-1.7%**	-8	**-0.1%**	1,279	**0.9%**
Total	**125,168**		**11,589**		**149,499**	

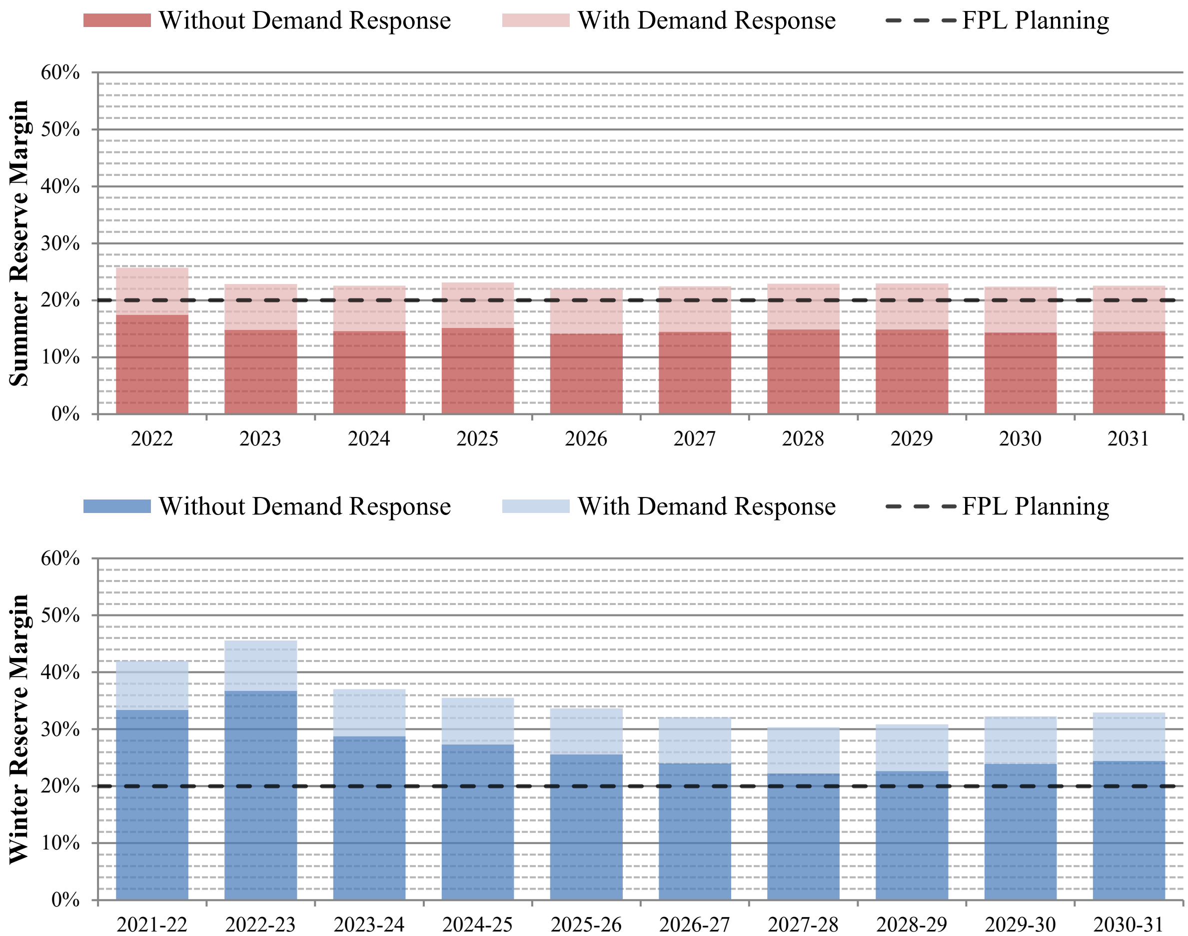
Source: 2022 Ten-Year Site Plan

Reliability Requirements

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

Since 1999, FPL has utilized a 20 percent reserve margin criterion for planning based on a stipulation approved by the Commission. Figure 21 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 21: FPL Reserve Margin Forecast



Source: 2022 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.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period. These changes are described in Table 14. Six units totaling 1,501 MW of coal generation are being retired, including FPL's partial ownership of Scherer Units 3 & 4 and Daniel Units 1 & 2.

FPL is only constructing one new natural gas-fired unit, the Dania Beach Clean Energy Center, a combined cycle unit, which is expected to go into service by mid-2022. In addition, FPL plans upgrades to several of its natural gas combustion turbines totaling 370 MW in additional capacity over the planning period. However, the majority of changes on FPL's system are from solar photovoltaic plants, adding approximately 9,314 MW at approximately 130 sites. Also, FPL anticipates adding a total of 1,800 MW of battery storage in the latter years of the planning period.

Table 14: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (MW) Sum	Notes
Retiring Units					
2022	Scherer 4	BIT- ST	634		
2022	Lansing Smith	DFO - GT	32		
2024	Daniel 1 & 2	BIT- ST	502		
2025	Pea Ridge 1-3	NG - CT	12		
2025	Gulf Energy Center Units 4 &5	BIT - ST	150		
2029	Scherer	BIT- ST	215		
2029	Perdido	LFG - IC	3		
Total Retirements			**1,548**		
New Units					
2022	Dania Beach Clean Energy Center	NG - CC	1,258	N/A	Docket No. 20170225-EI
2022	Sited Solar Facilities	PV	447	155	6 Known Solar Sites
2023	Sited Solar Facilities	PV	1,118	528	16 Known Solar Sites
2024	Sited Solar Facilities	PV	1,416	617	19 Known Solar Sites
2024	Unknown Solar	PV	224	98	7 Solar Sites
2025	Unknown Solar	PV	1490	542	20 Solar Sites
2026	Unknown Solar	PV	596	178	8 Solar Sites
2027	Unknown Solar	PV	596	156	8 Solar Sites
2028	Unknown Solar	PV	745	195	10 Solar Sites
2029	Unknown Solar	PV	894	190	12 Solar Sites
2029	Unsited Battery Storage	BAT	500	N/A	Multiple Sites
2030	Unknown Solar	PV	894	58	12 Solar Sites
2030	Unsited Battery Storage	BAT	700	N/A	Multiple Sites
2031	Unknown Solar	PV	894	58	12 Solar Sites
2031	Unsited Battery Storage	BAT	600		Multiple Sites
Total New Units			**12,372**	**2,775**	
Net Additions			**10,824**		

Source: 2022 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 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

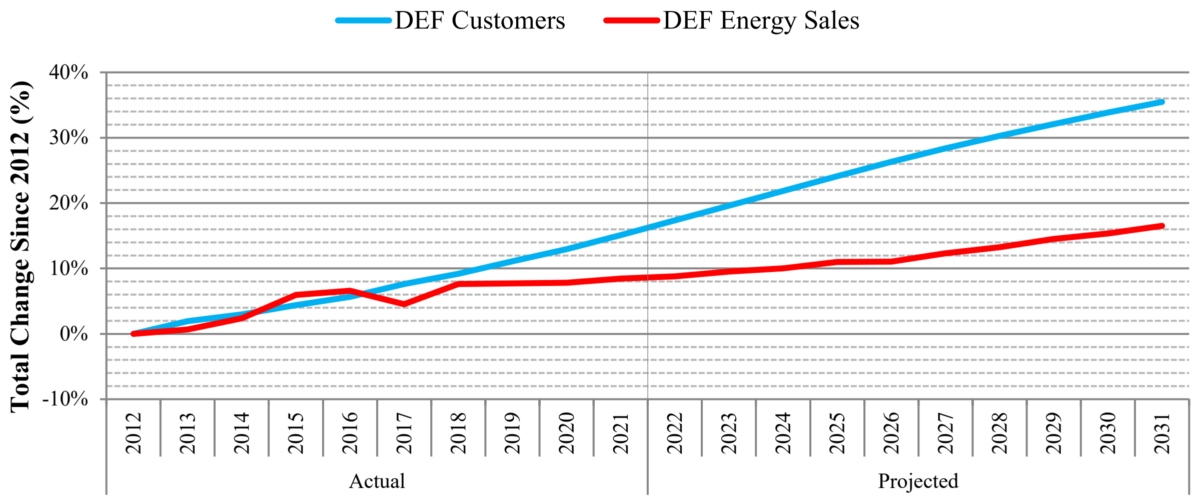
In 2021, DEF had approximately 1,898,726 customers and annual retail energy sales of 39,451 GWh or approximately 16.9 percent of Florida's annual retail energy sales. DEF's total customers grew approximately 1.87 percent in 2021. Figure 22 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, DEF's customer base has increased by 15.09 percent, while retail sales have grown by 8.44 percent.

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

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

For the 2022 TYSP forecast horizon, DEF's forecast results indicate that the utility's customer base is projected to grow at an average annual rate of 1.61 percent, and its retail energy sales are projected to grow at an average annual rate of 0.76 percent.

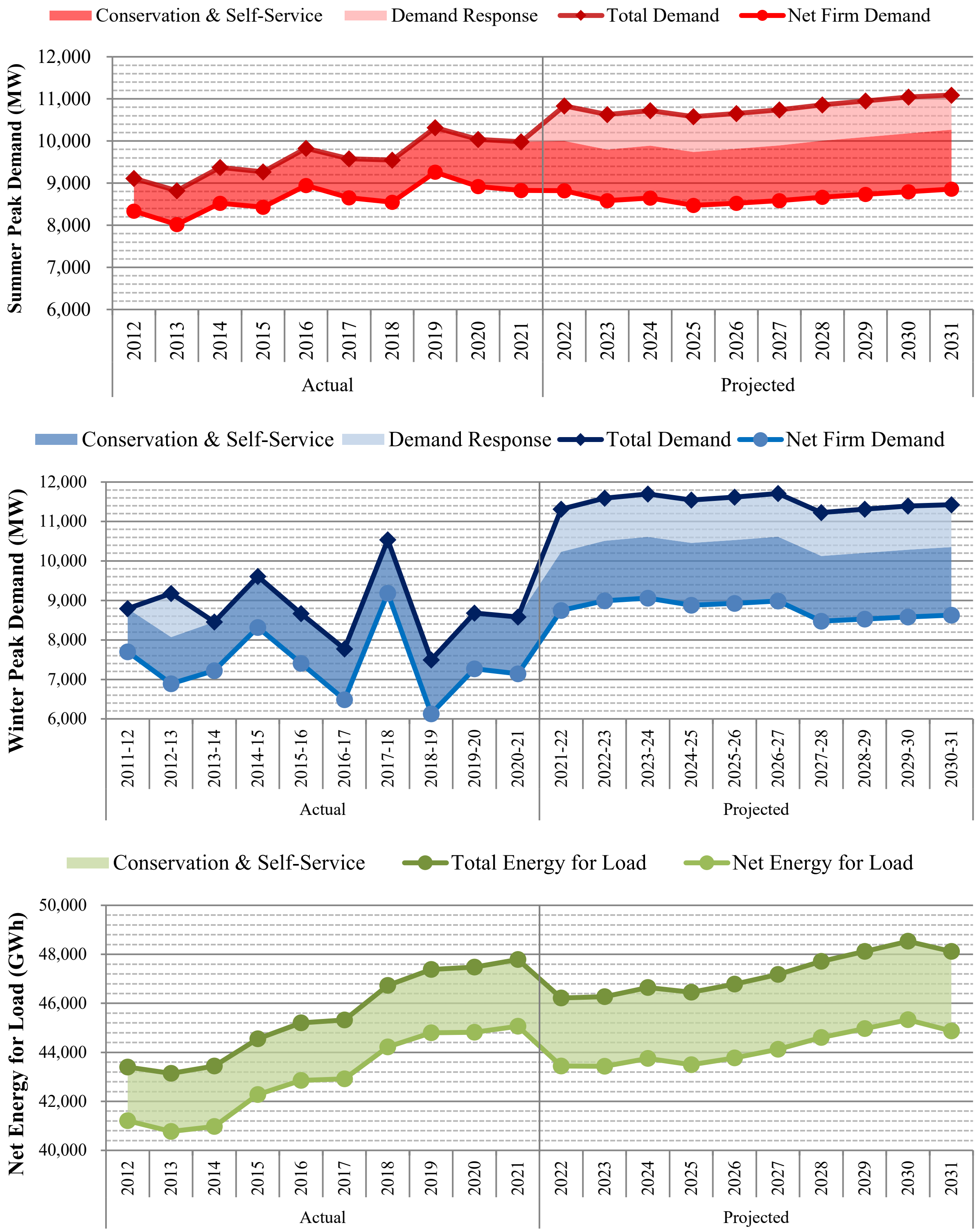
Figure 22: DEF Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 23 show DEF's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. 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. During the past 10 years, demand response has not been activated during seasonal peak demand. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for DEF for the years 2020 through 2024. In August 2020, the Commission approved DEF's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, DEF assumes trends in these goals will be extended through the forecast horizon (through 2031).

Figure 23: DEF Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 15 shows DEF's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. 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 in 2031. DEF projects the third highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 15: DEF Energy Generation by Fuel Type

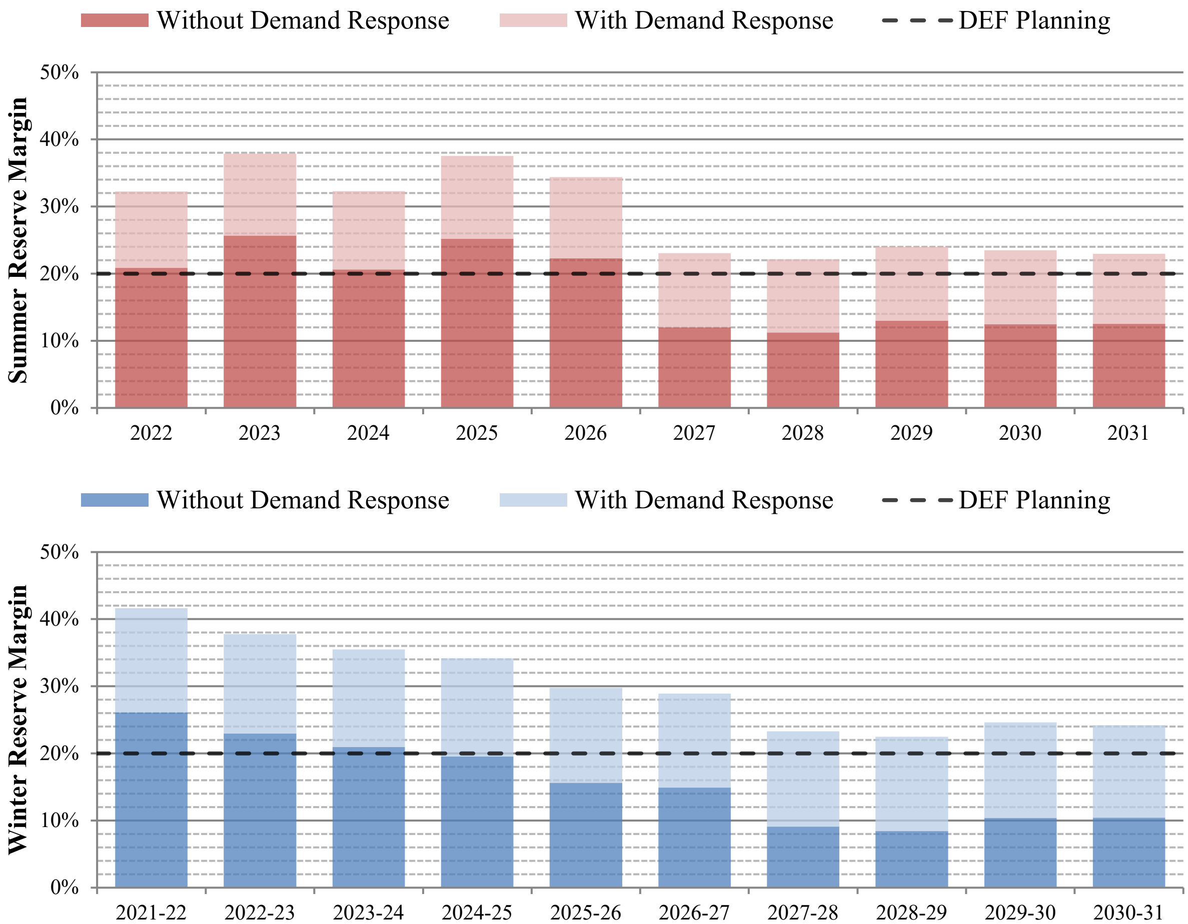
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	32,981	**73.2%**	33,318	**74.3%**
Coal	5,042	**11.2%**	1,548	**3.4%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	56	**0.1%**	4	**0.0%**
Renewable	1,551	**3.4%**	9,983	**22.2%**
Interchange	3,461	**7.7%**	17	**0.0%**
NUG & Other	1,974	**4.4%**	2	**0.0%**
Total	**45,065**		**44,872**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are mostly controlled by its summer peaking throughout the planning period.

Figure 24: DEF Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 16. DEF plans on retiring one gas and several oil-fired units at multiple power plant sites totaling 524 MW. DEF is adding a combustion turbine in 2029, at an undesignated site. Transmission upgrades are expected to be completed in 2024 that will allow DEF to fully utilize its existing Osprey facility, with the incremental available firm capacity listed in Table 16.

DEF has included 2,700 MW of planned solar additions, which make up approximately 73 percent of DEF's planned total new capacity. DEF also plans on adding 111 MW of storage capacity to be connected to its solar facilities. In July 2020, DEF petitioned the Commission to implement a Clean Energy Connection program (CEC), which is designed to be a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy centers.[15] The Order approving the CEC program was appealed to the Supreme Court of Florida. The Supreme Court remanded the decision back to the Commission, requesting a revised final

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

order to explain the Commissions finding and reasoning.[16] In addition to its utility-owned solar additions, DEF is also entering into several purchased power agreements with solar qualifying facilities for approximately 285 MW of capacity.

Table 16: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (Summer)	Notes
			Sum	Sum	
Retiring Units					
2025	Bayboro P1-4	DFO – CT	171	N/A	
2027	Debary P2-6	DFO – CT	227	N/A	
2027	Bartow P1 & 3	DFO – CT	82	N/A	
2027	University of Florida P1	NG – CT	44	N/A	
Total Retired MW			**524**	N/A	
New Units					
2022	Sited Solar Facilities	PV	300	172	4 Known Solar Sites
2023	Sited Solar Facilities	PV	300	172	4 Known Solar Sites
2024	Osprey	NG – CC	338	N/A	Transmission Upgrades
2024	Unknown Solar	PV	450	208	Multiple Sites
2025	Unknown Solar	PV	300	75	Multiple Sites
2026	Unknown Solar	PV	300	75	Multiple Sites
2027	Unknown Solar	PV	300	75	Multiple Sites
2028	Unknown Solar	PV	300	75	Multiple Sites
2029	Unknown Solar	PV	300	38	Multiple Sites
2029	Unknown CT	NG – CT	214	N/A	
2029	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2030	Unknown Solar	PV	300	38	Multiple Sites
2030	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2031	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2031	Unknown Solar	PV	300	38	Multiple Sites
Total New MW			**3,715**	**1,180**	
Net Additions			**3,172**		

Source: 2022 Ten-Year Site Plan

[16] Order No. PSC-2021-0059A-S-EI, issued September 23, 2022, in Docket No. 20200176-EI, *In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.*

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

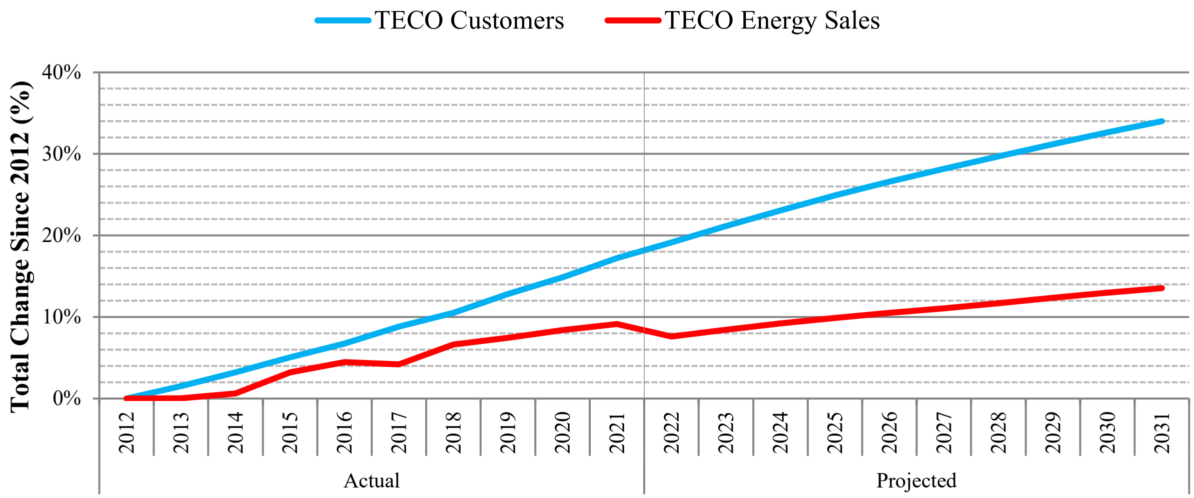
In 2021, TECO had approximately 802,050 customers and annual retail energy sales of 20,093 GWh or approximately 8.6 percent of Florida's annual retail energy sales. Figure 25 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, TECO's customer base has increased by 17.2 percent, while retail sales have increased by 9.1 percent.

TECO's total customer growth in 2021 averaged 2.0 percent with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.3 percent annually. The primary driver of customer growth will be new construction and increasing net in-migration to the utility's service area.

TECO's average annual energy consumption per residential customer decreased in 2021, primarily due to milder weather than in the prior year. In addition, the effects of COVID-19 are not as prevailing as in 2020, evidenced by people returning to work places/schools which results in a reduced residential energy consumption compared to what was experienced during the pandemic-triggered stay-at-home period. Over the next 10 years, the utility expects average energy consumption per residential customer to decline at an average annual rate of 0.4 percent. The primary drivers behind the decline are increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and changes in housing mix. TECO's commercial per customer usage in 2021 was 0.3 percent lower than in 2020, and such usage is projected to remain relatively flat over the current TYSP forecast horizon. The utility's industrial per customer usage in 2021 was 0.1 percent higher than what was achieved in 2020. This is mainly attributable to the industrial phosphate sector having less self-serving generation and more purchases from TECO. Over the forecast horizon, the average usage per industrial customer is expected to decrease slightly by an average of 0.1 percent per year.

For the next 10 years, TECO's retail energy sales are projected to grow at an annual average rate of 0.6 percent. This is below the customer growth rate of 1.3 percent primarily due to continued per customer energy consumption declines in the residential sector, as well as declines in the phosphate sector as the mining industry continues to move south and out of the utility's service territory.

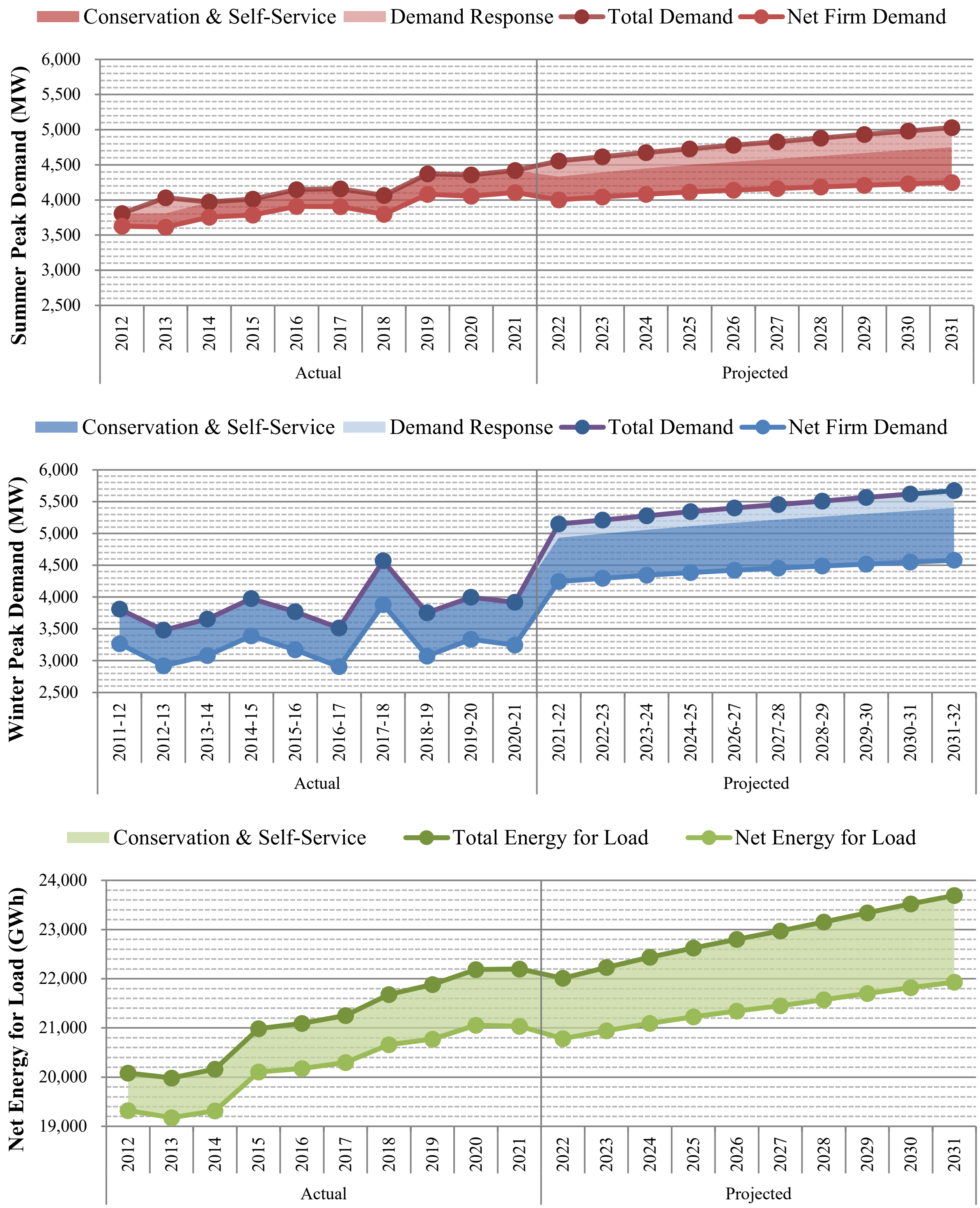
Figure 25: TECO Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 26 show TECO's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. 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 the summer of 2013 and winters of 2017-2018 and 2018-2019. As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for TECO for the years 2020 through 2024. In August 2020, the Commission approved TECO's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, TECO assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 26: TECO Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 shows TECO's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. Based on its 2022 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 77 percent of net energy for load. In the future, TECO projects that energy from coal will decrease and energy from renewables will increase. TECO projects that renewable energy will increase from 6.0 percent to 20.4 percent by 2031. TECO projects the fourth highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 17: TECO Energy Generation by Fuel Type

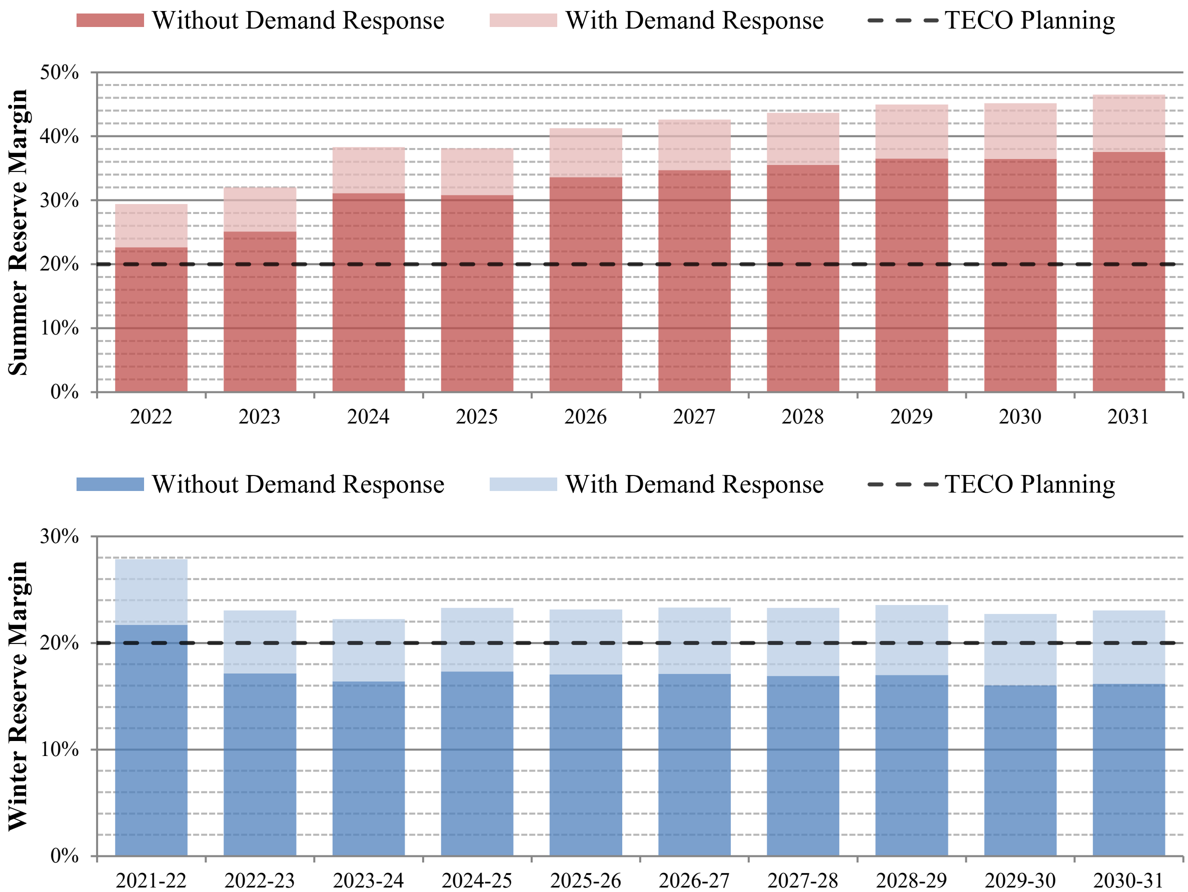
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	16,124	**76.7%**	17,278	**78.8%**
Coal	1,358	**6.5%**	160	**0.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	1,252	**6.0%**	4,481	**20.4%**
Interchange	77	**0.4%**	0	**0.0%**
NUG & Other	2,220	**10.6%**	12	**0.1%**
Total	**21,033**		**21,931**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 27 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are being controlled by its winter peak. TECO's current and planned investments in solar generation contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

Figure 27: TECO Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

TECO plans one unit retirement and multiple unit additions during the planning period, as described in Table 18. TECO anticipates retiring its natural gas-fired Big Bend Unit 3. For natural gas-fired units, TECO plans to add two internal combustion units and convert Big Bend Unit 1, a former coal unit, along with Big Bend Units CT5 and CT6 into a combined cycle configuration, providing an incremental 395 MW of generation. TECO also anticipates adding several solar projects over the planning period totaling 1,342 MW, supplemented by the addition of 275 MW of battery storage.

Table 18: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (Summer)	Notes
			Sum	Sum	
				Retiring Units	
2023	Big Bend 3	NG – ST	395	N/A	
Total Retirements			**395**	N/A	
				New Units	
2022	Sited Solar Facilities	PV	361	202	6 Known Sites
2022	Big Bend Conversion	NG – CC	395	N/A	
2023	Sited Solar Facilities	PV	135	75	2 Known Sites
2023	Dover Solar + Storage 1	PV – BAT	25.0	15	15 MW of Batteries
2023	Unknown Solar	PV	74.5	41.6	
2024	Battery Storage 1	BAT	100	N/A	
2025	Unknown Solar	PV	300	167	Multiple Sites
2025	Reciprocating Engine 1	NG – IC	37	N/A	
2026	Unknown Solar	PV	74.5	41.6	
2027	Battery Storage 2	BAT	50	N/A	
2027	Unknown Solar	PV	74.5	41.6	
2028	Reciprocating Engine 2	NG – IC	37	N/A	
2028	Unknown Solar	PV	74.5	41.6	
2029	Battery Storage 3	BAT	50	N/A	
2029	Unknown Solar	PV	74.5	41.6	
2030	Unknown Solar	PV	74.5	41.6	
2031	Battery Storage 4	BAT	50	N/A	
2031	Unknown Solar	PV	74.5	41.6	
Total New Units			**2,179**	**760.2**	
Net Additions			**1,784**		

Source: 2022 Ten-Year Site Plan

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. For a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2022 Ten-Year Site Plan suitable for planning purposes.

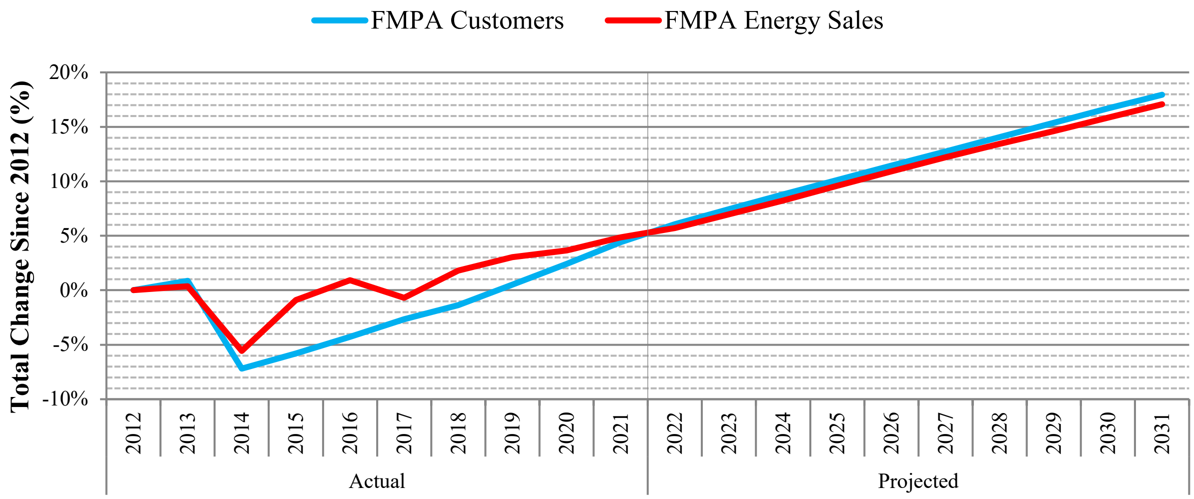
Load & Energy Forecasts

In 2021, FMPA had approximately 276,418 customers and annual retail energy sales of 5,944 GWh or approximately 2.5 percent of Florida's annual energy sales. Figure 28 illustrates the utility's historic and forecasted growth rates in customers and energy sales beginning in 2012. Over the last 10 years, FMPA's customer base has increased by 4.41 percent, while energy sales have increased by 4.85 percent.

FMPA's per-customer energy usage has been flat to declining in both the residential and non-residential sectors in recent years. In response to staff data requests, FMPA noted that there were countervailing factors that influence usage. In general, declines in electricity prices, improvements in the employment situation, increased average income, and reductions in vacancy rates and under-occupied accounts have a small upward impact on usage. Concurrently, the lingering effects of the recent recession in terms of reduced propensity to spend, a continued orientation to conservation, and continued improvement in energy efficiency, driven primarily from technological advances, equipment standards, and building codes, place downward pressure on average usage. These impacts have been offset by strong customer count gains in certain areas of the utility's service territories, which has resulted in continued recovery in net energy for load since the Great Recession. FMPA expects that an explicit projection of the impact of increased EV adoption will be infused into the forecast in the future.

For the current 10-year forecast horizon, the utility is projecting a 1.19 percent average annual growth rate for its customer base, and a 1.14 percent average annual growth rate for energy sales.

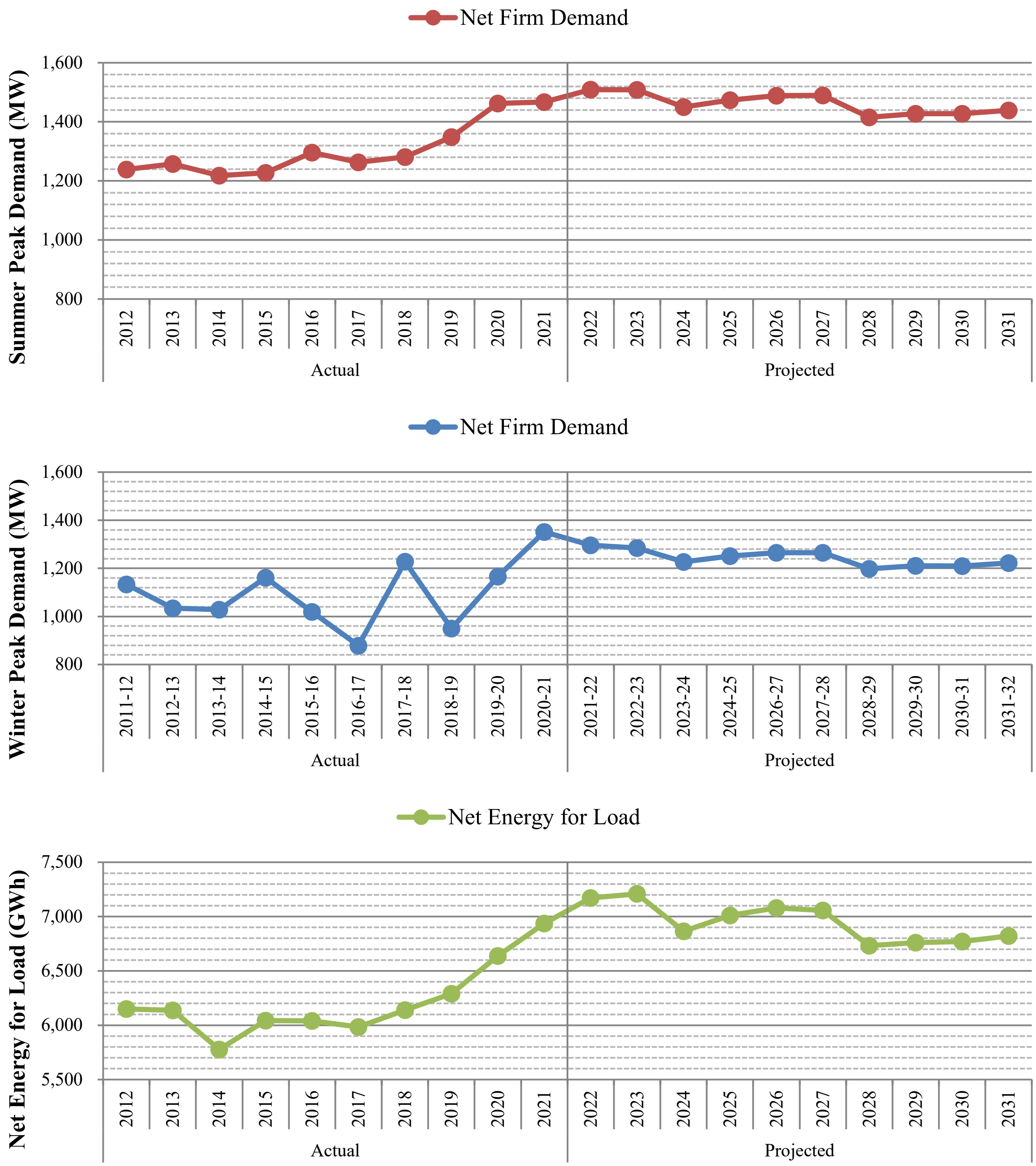
Figure 28: FMPA Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 29 show FMPA's seasonal peak demand and net energy for load for the historic years 2012 through 2021 and forecast years 2022 through 2031. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

Figure 29: FMPA Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows FMPA's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects to end energy generation from coal by 2026, but approximately 89 percent of energy would still be sourced from natural gas and nuclear. FMPA projects serving 11 percent of its net energy for load with renewable resources by the end of the planning period.

Table 19: FMPA Energy Generation by Fuel Type

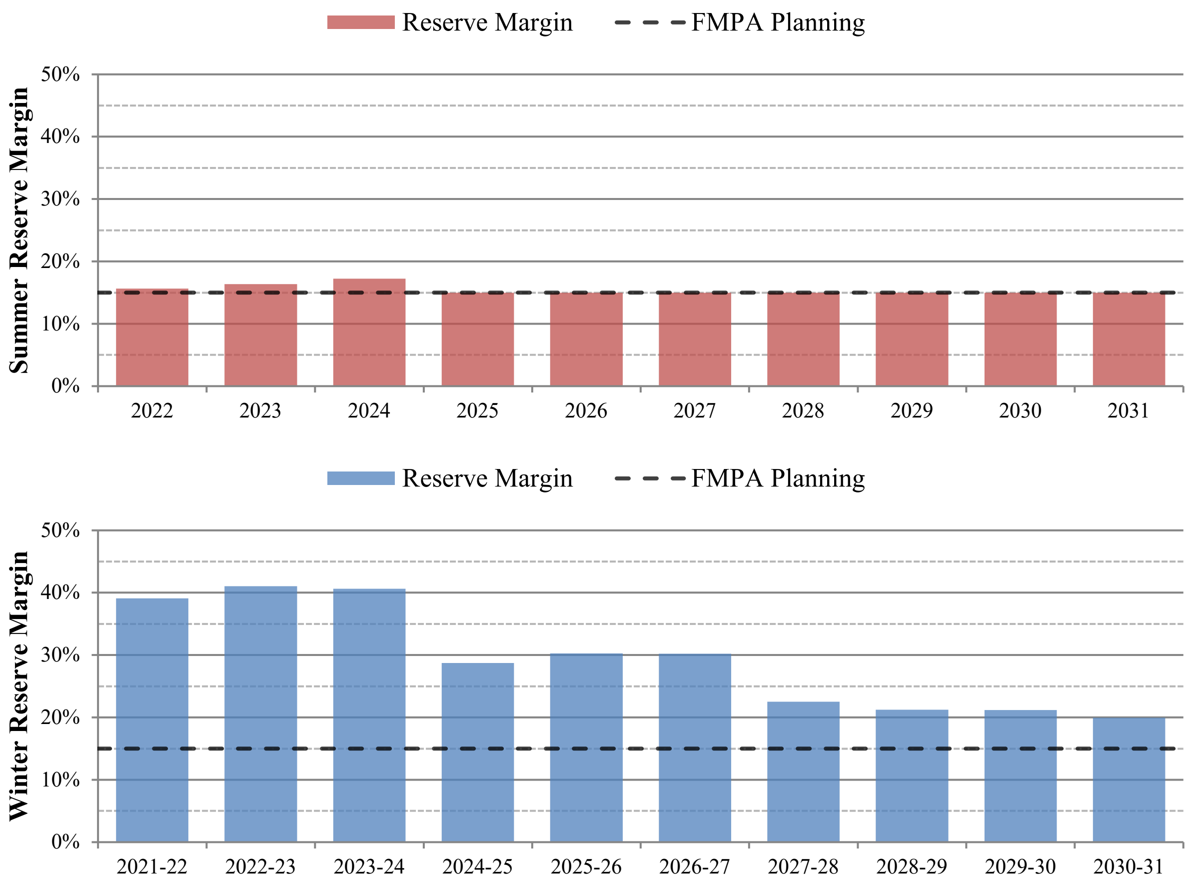
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	5,271	**76.0%**	5,675	**83.2%**
Coal	1,126	**16.2%**	0	**0.0%**
Nuclear	383	**5.5%**	390	**5.7%**
Oil	3	**0.0%**	1	**0.0%**
Renewable	154	**2.2%**	757	**11.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**6,937**		**6,823**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 30 displays the forecast planning reserve margin for FMPA through the planning period for both seasons. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 30: FMPA Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

FMPA plans on retiring Stanton Unit 1, a coal unit, in 2025 as described in Table 20. The utility also plans the conversion of Stanton Unit 2 from coal-fired to natural gas-fired in 2027. FMPA also has entered in two purchased power agreements (PPAs) that will add a total of 154 MW of solar capacity by the end of 2024. FMPA anticipates entering into additional PPAs that will add another 100 MW of solar capacity within the planning period.

Table 20: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	BIT – ST	118	Jointly Owned with OUC
Total Retirements			**118**	
Net Additions			**(118)**	

Gainesville Regional Utilities (GRU)

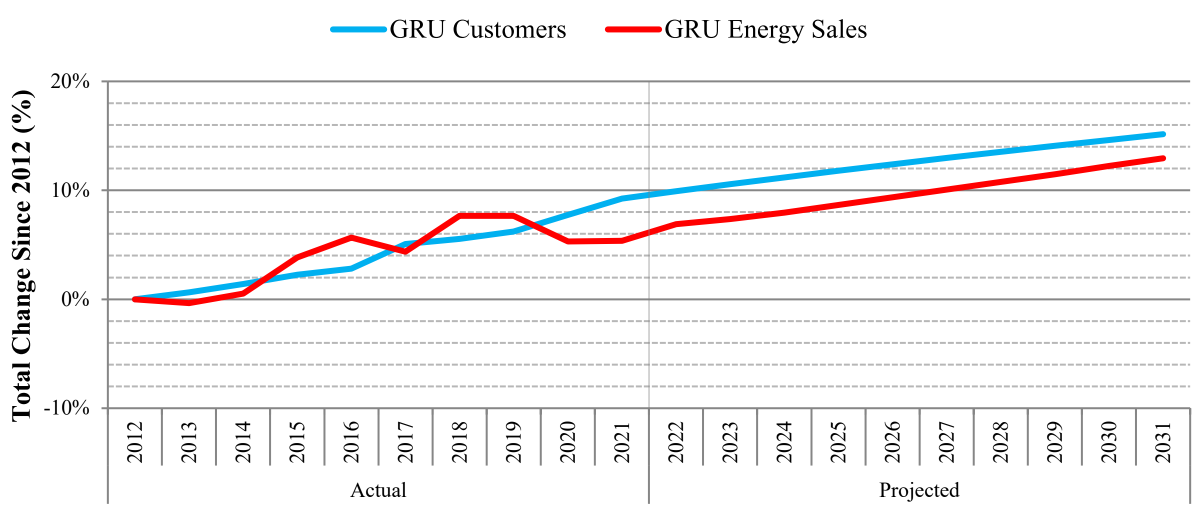
GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. 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 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2021, GRU had approximately 101,117 customers and annual retail energy sales of 1,791 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Over the last 10 years, GRU's customer base has increased by 9.25 percent, while retail sales have increased by 5.35 percent. Figure 31 illustrates GRU's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

GRU noted that over the past 10 years, its residential energy consumption per customer increased 0.15 percent per year, while its non-residential consumption per customer declined 0.84 percent per year. For the next 10 years, the utility projects that both residential and non- residential energy consumption per customer will stay constant. For the current 10-year forecast horizon, GRU's number of customers is projected to grow at an annual average rate of 0.52 percent, and its retail energy sales are projected to grow at an annual average rate of 0.61 percent. The utility indicated that its projected growth of retail energy sales is supported by its projected increase in the number of customers and, to a small degree, offset by flat or declining energy consumption per customer. The utility also noted that load associated with electric vehicle charging is anticipated to support energy sales more in this forecast than in past forecasts.

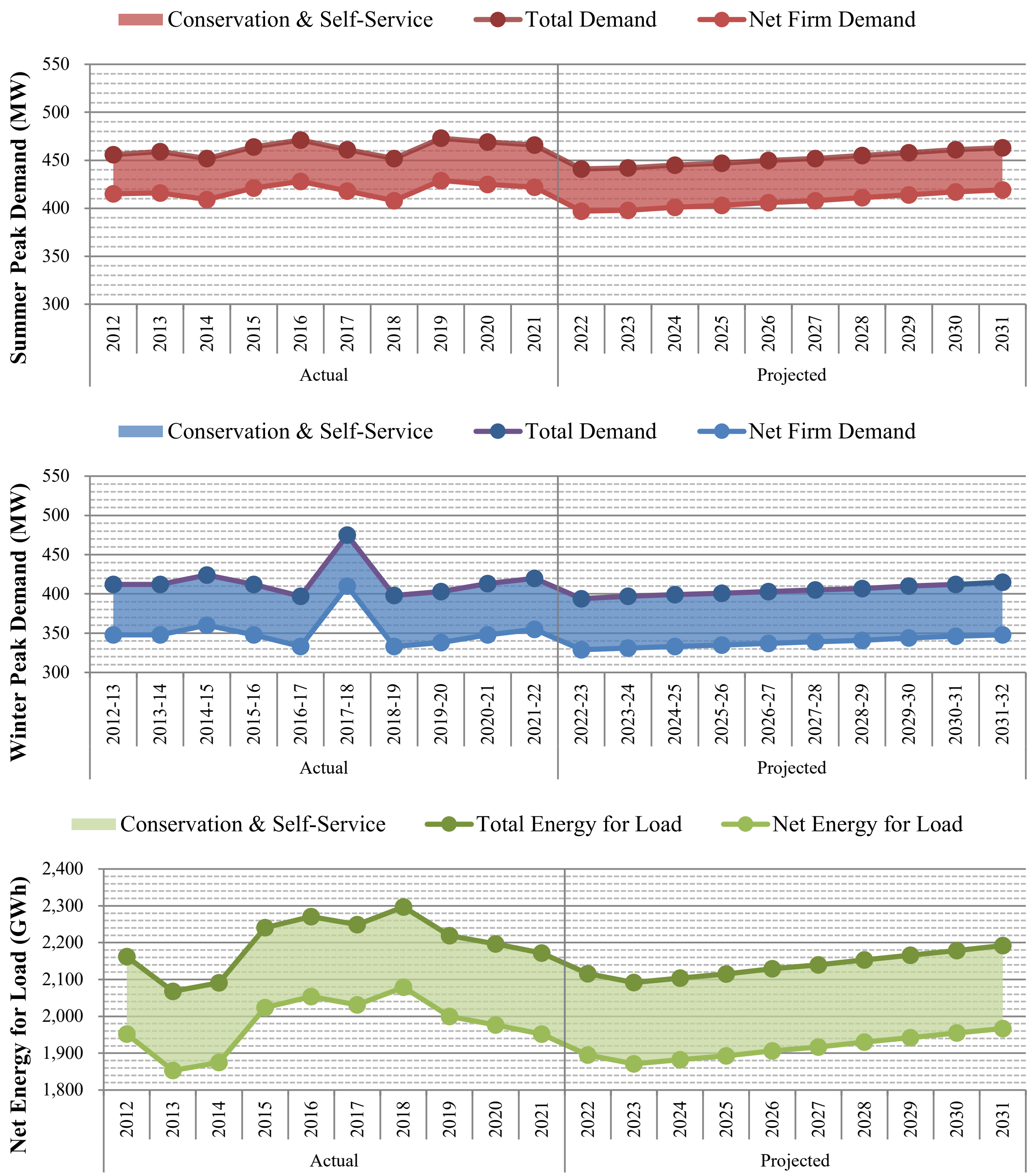
Figure 31: GRU Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 32 show GRU's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 32 include the impact of these demand-side management programs.

Figure 32: GRU Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021, natural gas was the primary fuel followed by renewables and coal respectively. GRU currently has the highest percentage contribution of renewables in Florida for net energy for load. By 2031 natural gas and renewables are expected to be the only generation, with coal-fired generation eliminated. GRU is forecasted to drop to the second highest percent contribution from renewables for net energy for load by 2031.

Table 21: GRU Energy Generation by Fuel Type

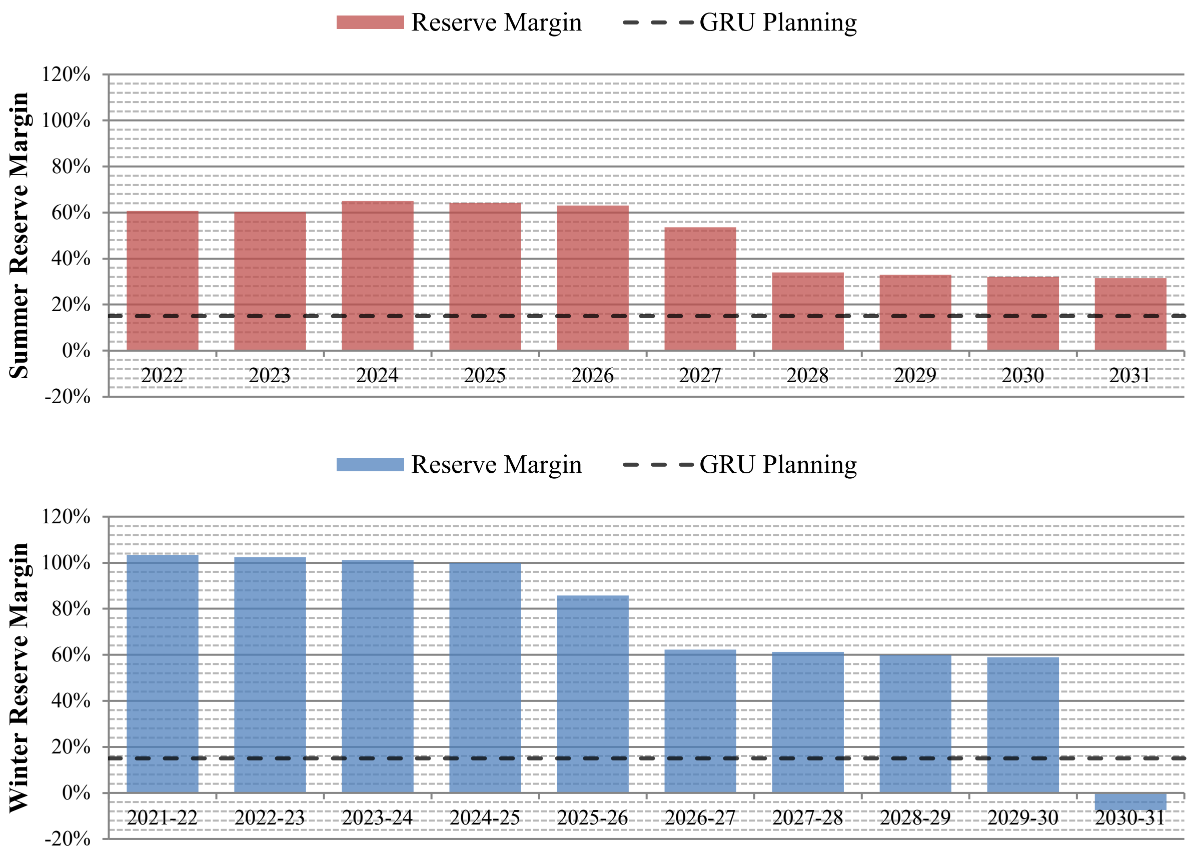
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	1,004	**51.4%**	1,389	**70.6%**
Coal	320	**16.4%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	6	**0.3%**	0	**0.0%**
Renewable	612	**31.4%**	586	**29.8%**
Interchange	10	**0.5%**	-8	**-0.4%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**1,952**		**1,967**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 33 displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. GRU's reserve margin, is projected to be negative in the Winter of 2030/31 due to a unit retiring in 2031. As GRU approaches this date, the utility will continue to evaluate how to meet its 15 percent reserve margin criterion. Staff believes this to be acceptable for planning purposes this year. Staff will evaluate future plans to ensure reserve margin is maintained.

Figure 33: GRU Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

GRU currently plans on retiring two natural gas-fired combustion turbines in 2026, a natural gas-fired steam unit in 2027, and a coal unit in 2031 as described in Table 22. GRU entered into a 20 year contact that is expected to deliver an additional 50 MW of solar capacity, 27.5 MW of which are considered firm, through a PPA with an expected in-service year of 2024.

Table 22: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2026	Deerhaven GT01 & GT02	NG – CT	35
2027	Deerhaven FS01	NG – ST	75
2031	Deerhaven FS02	BIT – ST	228
Total Retirements			**338**
Net Additions			**(338)**

Source: 2022 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 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

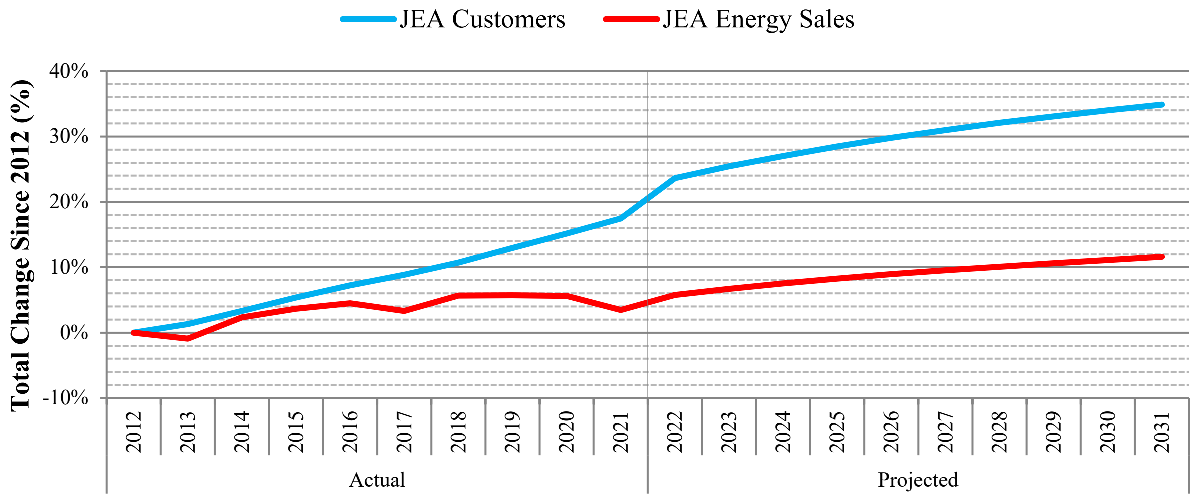
In 2021, JEA had approximately 493,039 customers and annual retail energy sales of 12,066 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 34 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, JEA's customer base has increased by 17.45 percent, while retail sales have increased by 3.45 percent.

JEA indicated that, overall, Moody's Analytics forecast for all parameters used in the utility's 2022 TYSP forecast of customer growth are lower as compared to the previous forecasts. As a result, JEA noted a lower forecast for customers as compared to its 2021 forecast.

JEA projected that the average annual energy consumption per customer will decrease by 0.3 percent and 1.1 percent, respectively, for residential and commercial classes over the forecasted 10-year period. The utility noted that demand-side management programs, customer behavioral change, the increase in electric rates, as well as housing type and federal central air conditioner-related requirements are contributors to these declines in per-customer energy consumption. However, JEA expects a small growth of 0.1 percent in average annual industrial energy consumption for the next 10 years.

For the next 10 years, the JEA's forecast results indicate that the customer numbers are projected to grow at an average annual rate of 0.97 percent; and the retail energy sales are projected to grow at an average annual rate of 0.81 percent.

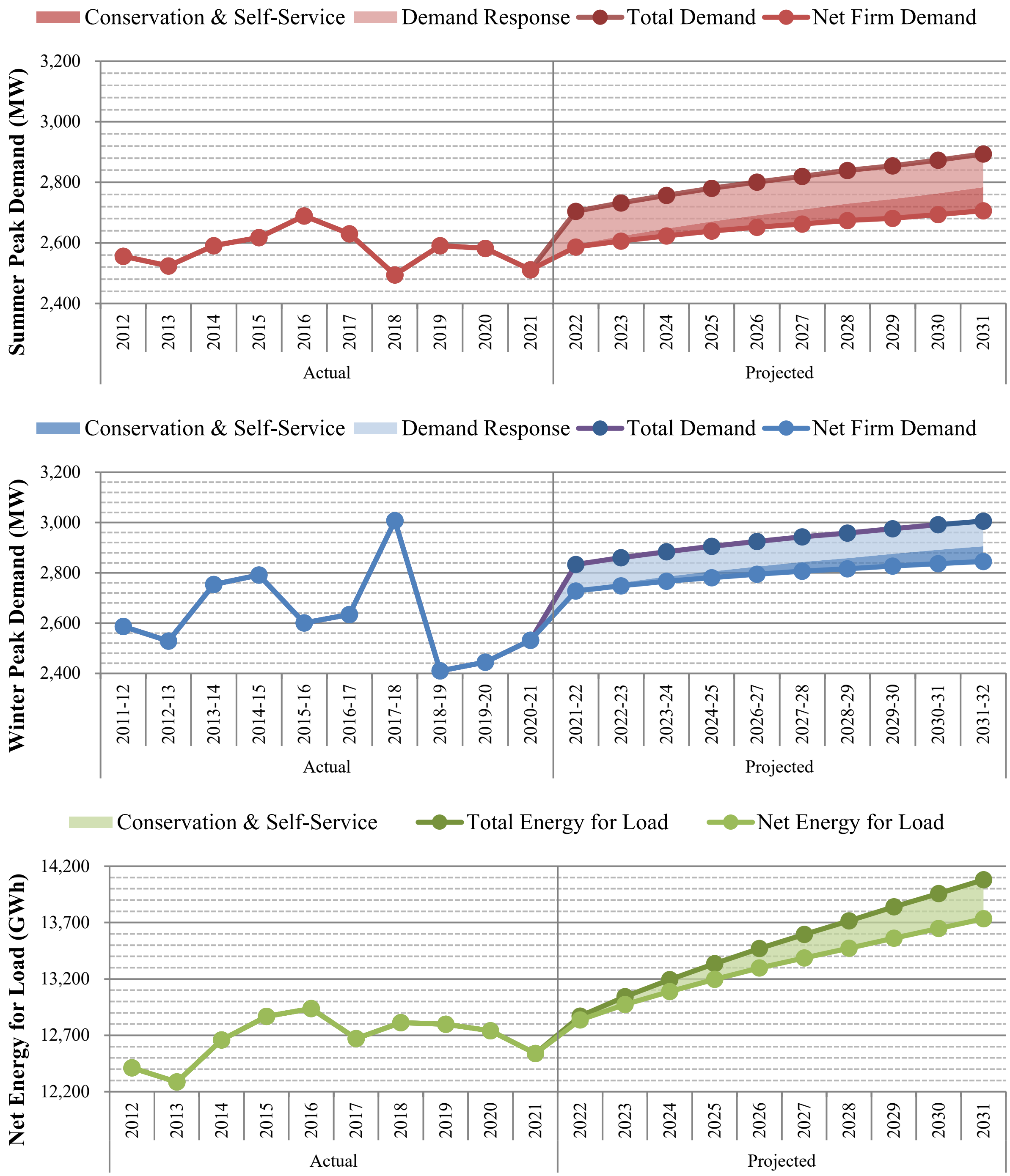
Figure 34: JEA Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 35 show JEA's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. 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. 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. In November 2019, the Commission established demand side management goals for JEA for the years 2020 through 2024. In July 2020, the Commission approved JEA's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, JEA assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 35: JEA Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. While natural gas was the dominant fuel source in 2021, coal was JEA's second most utilized fuel source. JEA's 2022 Ten-Year Site plan projects that a JEA will reduce its use of coal while increasing purchases. JEA has the highest percentage of energy from interchange, primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the nuclear Vogtle Units 3 and 4.

Table 23: JEA Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	7,673	**61.2%**	7,617	**55.5%**
Coal	2,742	**21.9%**	2,570	**18.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	16	**0.1%**	28	**0.2%**
Renewable	166	**1.3%**	82	**0.6%**
Interchange	1,943	**15.5%**	3,437	**25.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,540**		**13,734**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned purchased power agreements with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak.

Figure 36: JEA Reserve Margin Forecast

Source: 2022 Ten-Year Site Plan

Generation Resources

JEA retired its share of Scherer Unit 4 on January 1, 2022, as detailed in Table 24. JEA plans no unit additions during the planning period.

Table 24: JEA Energy Generation by Fuel Type

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2022	Scherer Unit 4	BIT - ST	198	Jointly Owned with FPL
Net Additions			**(198)**	

Source: 2022 Ten-Year Site Plan

Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

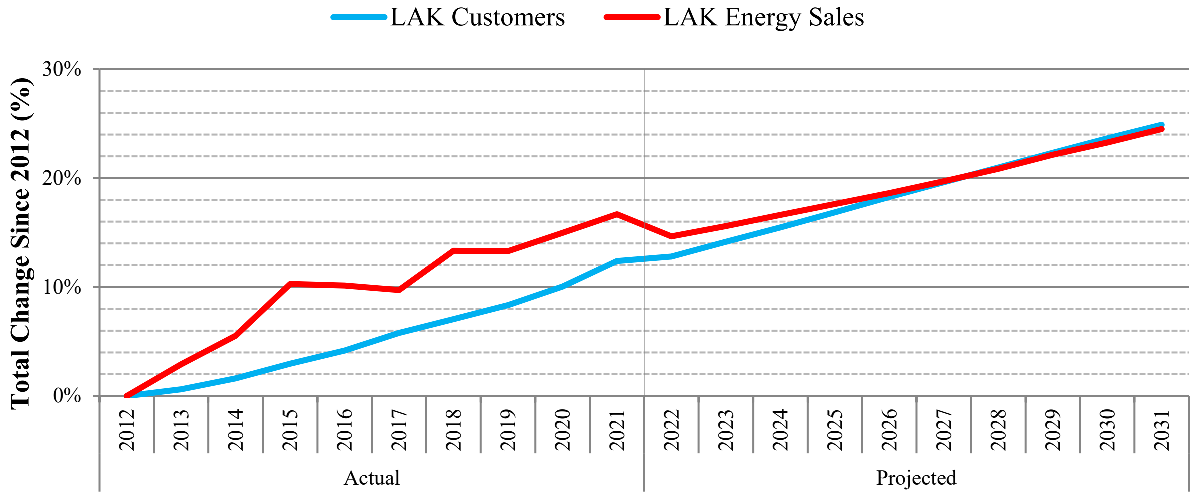
In 2021, LAK had approximately 137,162 customers and annual retail energy sales of 3,210 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Figure 37 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, LAK's customer base has increased by 12.68 percent, while retail sales have grown by 16.48 percent.

In recent years, LAK's service area in Polk County has seen a boom in e-commerce warehouse development. Particularly, LAK has benefited from the relocation of Amazon's air-hub to the utility's service area in 2020 and the continuing trend of work from home. As a result, LAK experienced 2.2 percent total customer growth in 2021, the highest growth rate for the utility in the past 10 years.

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

LAK noted that, although the average energy consumption per customer is declining or flat for all three main rate classes, positive customer growth rates are expected to compensate for average use declines. The utility assumed the impact of conservation programs are already in the energy sales history and made no additional assumptions regarding their impact. For the next 10 years, the utility's forecast results indicated that its number of customers are projected to grow at an average annual rate of 1.14 percent, and its retail energy sales are projected to grow at an average annual rate of 0.92 percent.

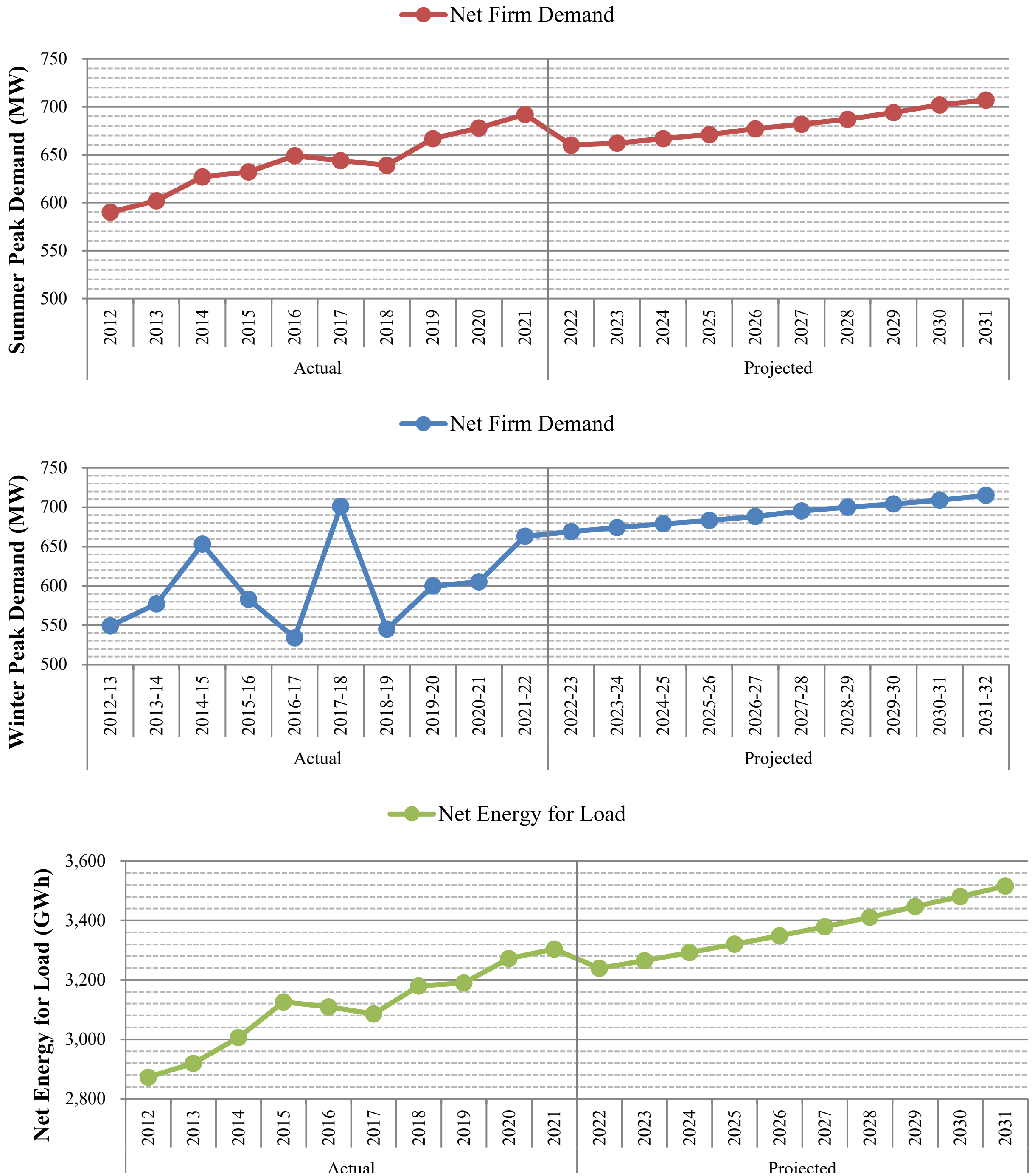
Figure 37: LAK Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 38 show LAK's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 38: LAK Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. LAK uses natural gas as its primary fuel type for energy, with coal representing about 13 percent net energy for load. While natural gas generation is anticipated to increase over the next 10 years; generation by coal is projected to be phased out by 2031.

Table 25: LAK Energy Generation by Fuel Type

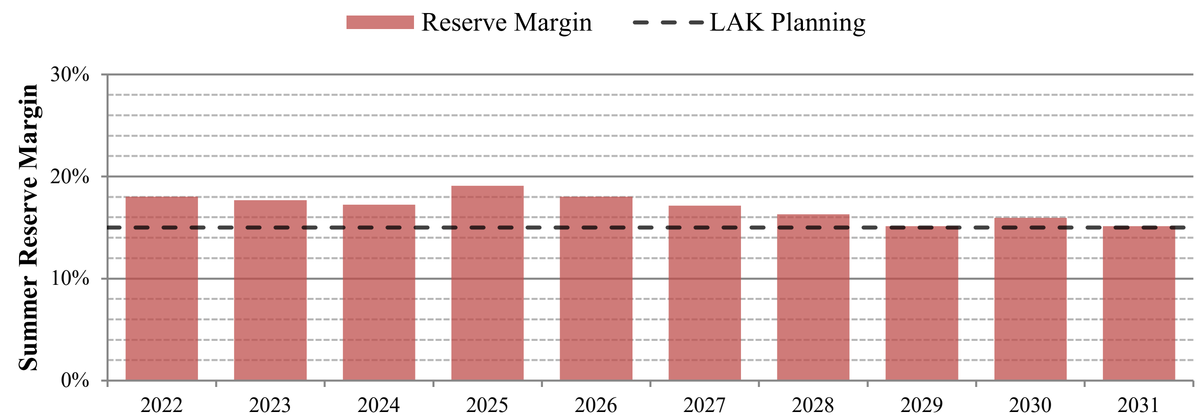
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	2,208	**66.8%**	3,071	**87.3%**
Coal	434	**13.1%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	26	**0.8%**	153	**4.4%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	636	**19.2%**	292	**8.3%**
Total	**3,304**		**3,516**	

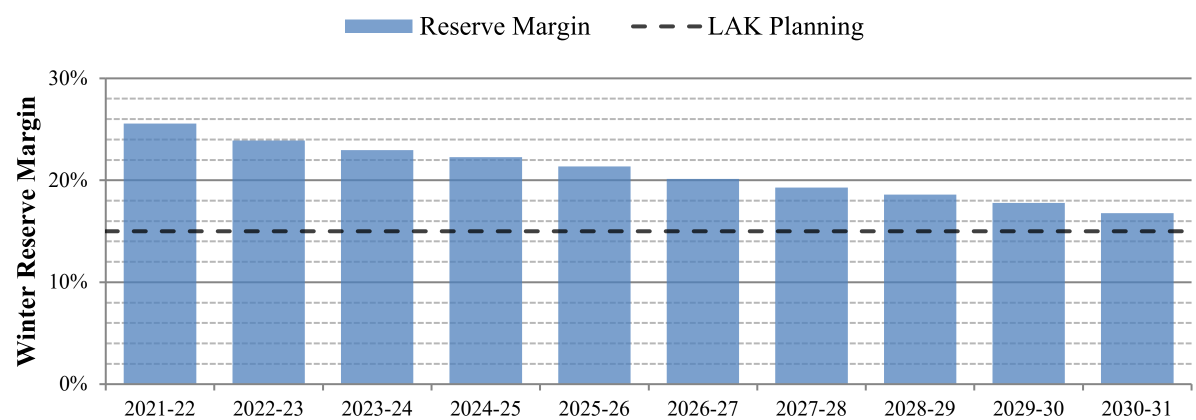
Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 39 displays the forecast planning reserve margin for LAK through the planning period for both seasons. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represented 50 percent of summer net firm peak demand in 2019.

Figure 39: LAK Reserve Margin Forecast





Source: 2022 Ten-Year Site Plan

Generation Resources

LAK is adding a set of solar sites and natural gas internal combustion engines during the planning period, as detailed in Table 26. LAK is also adding approximately 50 MW of additional capacity through PPAs during the planning period.

Table 26: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (MW)	Notes
			Sum	Sum	
New Units					
2024	McIntosh	PV	16	8	
2024	Mcintosh Units ME1-ME-6	NG-IC	120	N/A	6 Reciprocating Engines
2025	McIntosh	PV	34	17	
Net Additions			**170**	**25**	

Source: 2022 Ten-Year Site Plan and Data Responses

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's sixth 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 2022 Ten-Year Site Plan suitable for planning purposes.

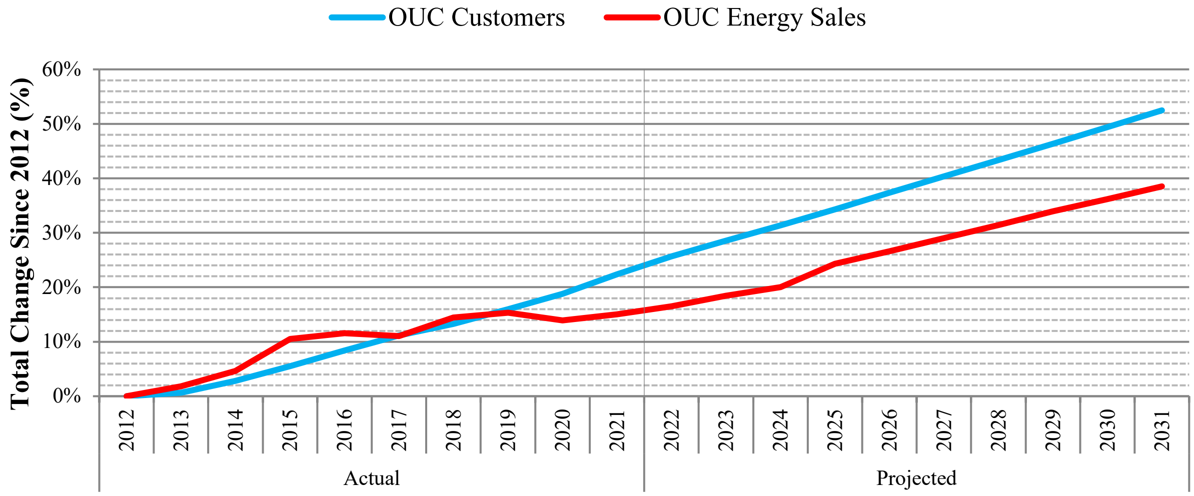
Load & Energy Forecasts

In 2021, OUC had approximately 261,045 customers and annual retail energy sales of 6,807 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 22.37 percent, while its retail energy sales have increased by 15.06 percent, approximately. Figure 40 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

OUC experienced a continued decline in average use per residential customer in 2021. The utility noted that such decline has tapered dramatically since the beginning of the 10-year historic period due to the increased saturation of more efficient HVAC equipment and other electrical devices, as well as customer conservation efforts. OUC's forecasted residential average per-customer usage is expected to remain relatively flat as increased electric vehicle charging mitigates further saturation of more efficient electrical equipment and conservation efforts. The utility's average use per commercial customer also experienced a slight, long-term decline, which was greatly exacerbated by the impacts of COVID-19, but is expected to return to pre-COVID levels.

Over the forecast horizon, OUC is projecting growth in the number of customers at a slightly increased average annual rate of 2.17 percent, and retail sales at a moderately increased average annual rate of 1.94 percent. OUC noted that the main contributors to the projected higher customer growth rate include the increased population and household numbers in its service area. The main drivers for the projected higher growth rate of the energy sales than what was projected in the past include the recovery from COVID-19 effects, the projected growth in electric vehicle charging load, and major commercial expansions by Universal Studios and the Orlando International Airport.

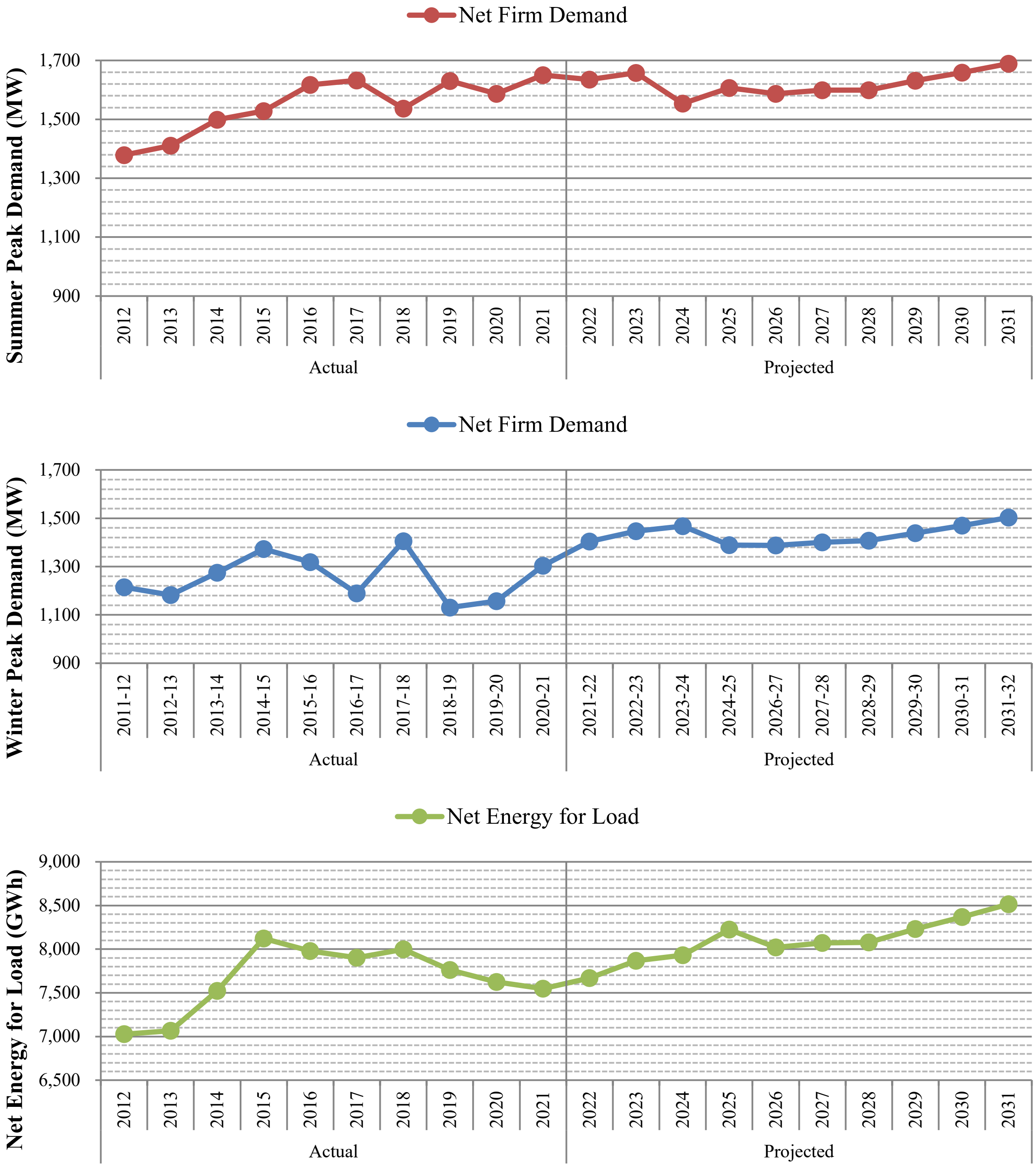
Figure 40: OUC Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 41 show OUC's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the impact of the utility's demand-side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for OUC for the years 2020 through 2024. In June 2020, the Commission approved OUC's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, OUC assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 41: OUC Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 27 shows OUC's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021, approximately 48 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met 42 percent of the demand. By 2031, OUC projects an increase in renewable energy generation from 5 percent to 55.9 percent, the highest in the state and the only utility projected to meet a majority of its net energy for load through renewables. The remainder of energy primarily comes from natural gas and nuclear, with coal generation completely eliminated.

Table 27: OUC Energy Generation by Fuel Type

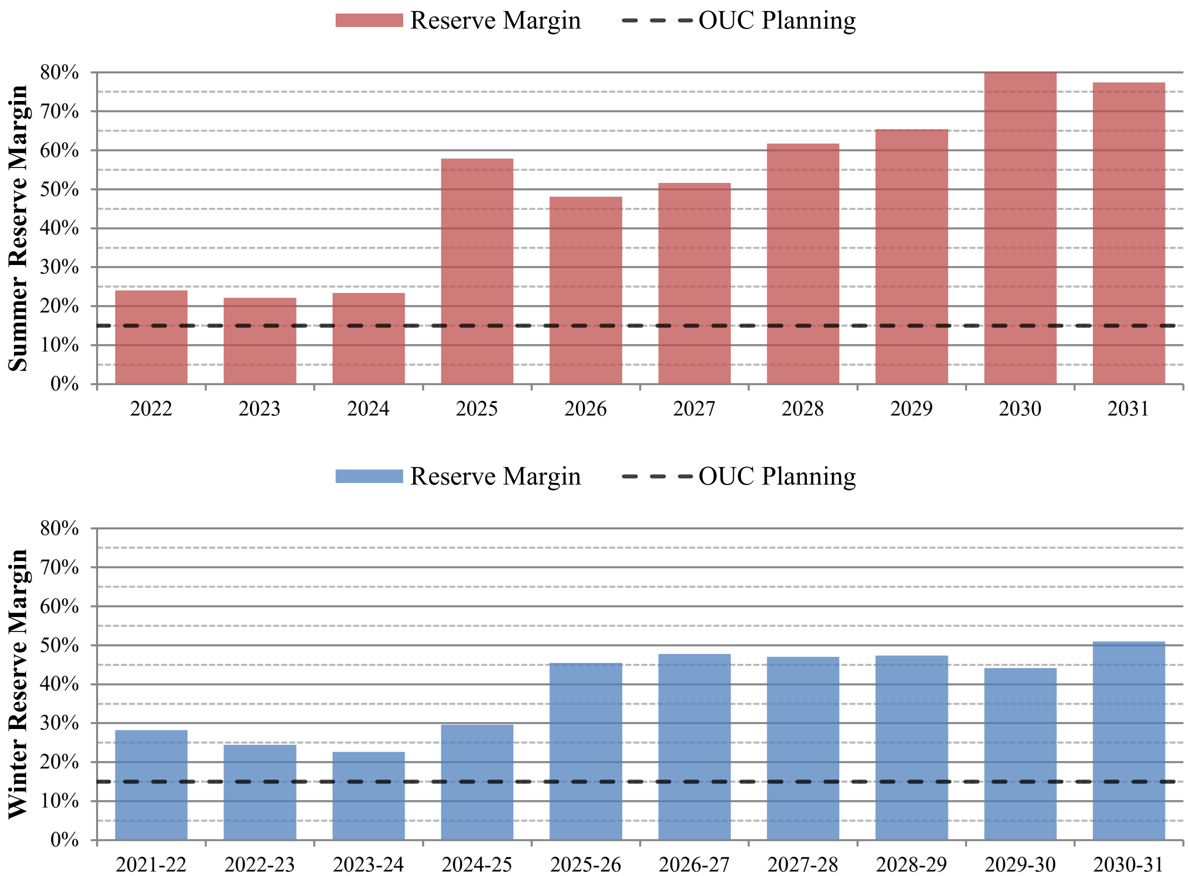
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	3,583	**47.5%**	3,173	**37.3%**
Coal	3,152	**41.8%**	0	**0.0%**
Nuclear	464	**6.1%**	578	**6.8%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	349	**4.6%**	4,764	**55.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,548**		**8,515**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand until 2024.

Figure 42: OUC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

As detailed in Table 28, OUC plans on retiring one coal-fired unit and adding three natural gas-fired units. OUC plans on retiring Stanton Unit 1, OUC's oldest coal-fired unit, no later than 2025. OUC also plans on converting Stanton Unit 2 from a coal unit to a natural gas unit in 2027. After the conversion in 2027, OUC plans to no longer burn coal as a fuel source. OUC is purchasing the existing Osceola Generating Station Units 1 through 3, natural gas-fired combustion turbines; but, will not be able to fully utilize their capacity during peak periods until 2025. Portions of their capacity will be available before that for summer peaks beginning in 2022.

OUC anticipates entering into PPAs for a total of 1,417 MW of solar capacity and 350 MW of storage. OUC has already signed two of these PPA with NextEra for a total of 149 MW of solar capacity and 40 MW of storage with a planned in-service year of 2023. The additional solar capacity produced by these PPAs will help OUC achieve their pledge of reducing carbon emissions 50 percent by the year 2030.

Table 28: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	BIT – ST	312	Jointly Owned with FMPA
Total Retirements			**312**	
New Units				
2025	Osceola Generating Station Units 1-3	NG – GT	471	Purchase of existing units.
Total New Units			**471**	
Net Additions			**159**	

Source: 2022 Ten-Year Site Plan

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 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

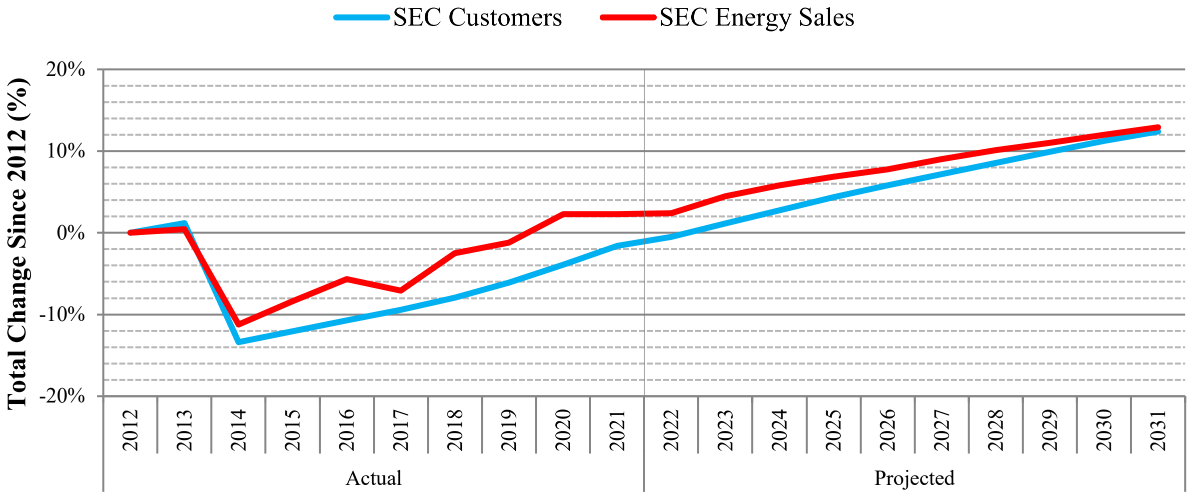
In 2021, SEC member cooperatives had approximately 841,276 customers and annual retail energy sales of 14,930 GWh or approximately 6.4 percent of Florida's annual retail energy sales. Figure 43 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

SEC's current TYSP indicated that over the last 10 years, 2012-2021, the utility members' aggregate customer base has decreased by 1.61 percent, compared to a 3.22 percent decrease shown in SEC's 2021 TYSP for the 2011-2020 period. The negative 10-year customer growth rate is attributed to a substantial growth decline in 2014 when one member cooperative, Lee County Electric Cooperative, elected to end its membership with SEC. In the current TYSP, the utility reported that its retail sales have increased by 2.27 percent over the historical period 2012-2021, compared to 0.03 percent decrease indicated in its 2021 TYSP for 2011-2020.

SEC states that historically, consumer growth in the Seminole-Member system has grown at a faster rate than the State of Florida as a whole and this trend is expected to continue. The utility noted that the leading indicators for load growth are Florida's expanding economy and net migration prospects into the state, especially from "baby boomer" retirees, and migration impacts of the COVID-19 pandemic. Customer growth and business activity are expected to drive system growth, while downward pressure is expected to come from flattening and declining residential end-use due to growth in efficient technologies, renewable generation, and alternative resources.

Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 1.36 percent, and an average annual growth rate in its retail energy sales of 1.09 percent.

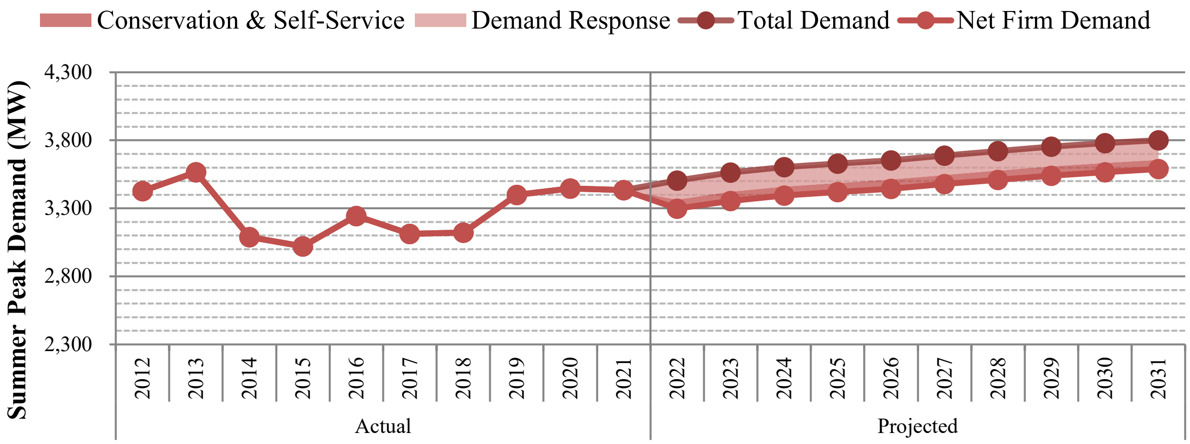
Figure 43: SEC Growth

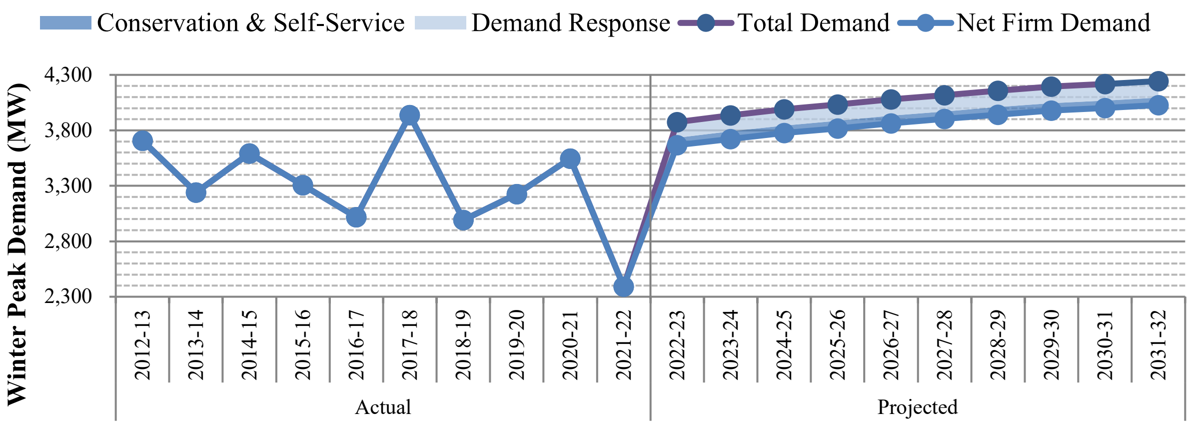


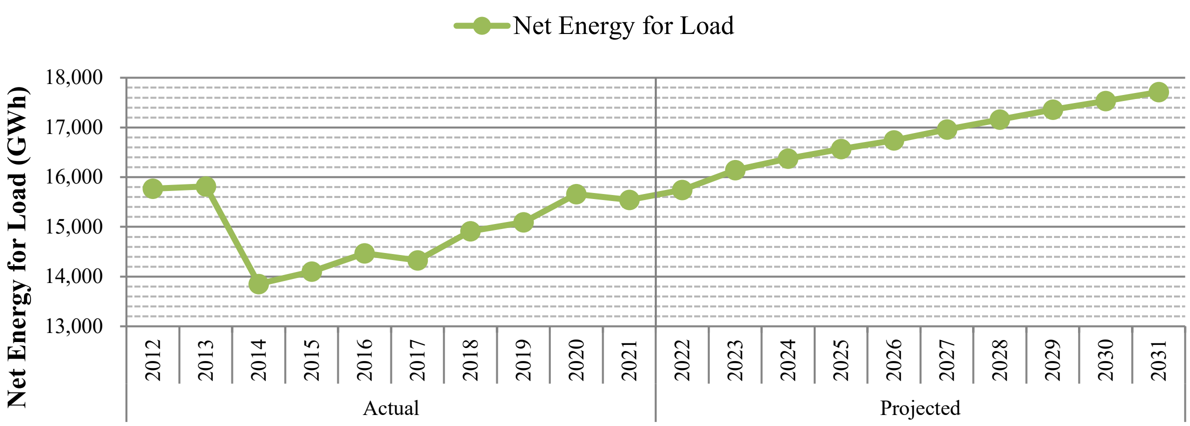
Source: 2022 Ten-Year Site Plan

The three graphs in Figure 44 show SEC's seasonal peak demand and net energy for load for the historic years 2012 through 2021 and forecast years 2022 through 2031. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 44.

Figure 44: SEC Demand and Energy Forecasts







Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 29 shows SEC's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021 SEC used coal as its primary source of fuel. By 2031 natural gas usage is expected to become the primary fuel source.

Table 29: SEC Energy Generation by Fuel Type

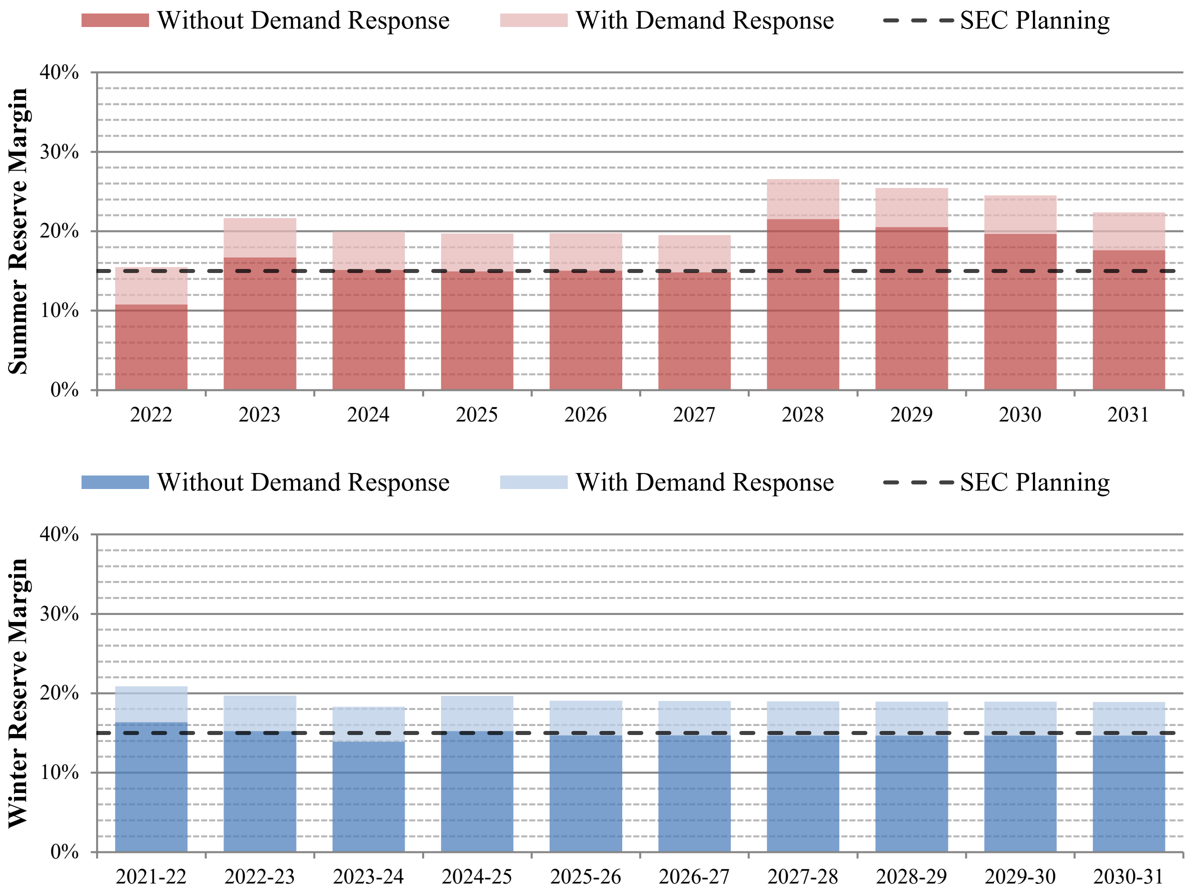
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	4,180	**26.9%**	14,673	**82.8%**
Coal	6,508	**41.9%**	1,637	**9.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	21	**0.1%**	4	**0.0%**
Renewable	489	**3.1%**	766	**4.3%**
Interchange	4,343	**27.9%**	631	**3.6%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**15,541**		**17,711**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 45 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 45: SEC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add two units during the planning period, as described in Table 30. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[17] SEC plans on retiring one of its coal-fired SGS units at the end of 2022; but, has not yet selected the generator. In addition, SEC plans to add two natural gas-fired generating resources, a combined cycle and combustion turbine, during the planning period. SEC considers these as proxy units to meet its reliability criteria due to ending PPA contracts. SEC anticipates an additional 300 MW of solar generation through PPAs to become commercially operational by the end of 2023.

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

Table 30: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2022	SGS Unit 1 or 2	BIT – ST	626	Unit choice for retirement pending.
Total Retirements			**626**	
New Units				
2022	Seminole CC Facility	NG – CC	1,099	Docket No. 20170266-EC
2025	Unnamed CC	NG – CC	571	
2027	Unnamed CT	NG – CT	317	
Total New Units			**1,987**	
Net Additions			**1,361**	

Source: 2022 Ten-Year Site Plan

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility that 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 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2021, TAL had approximately 125,901 customers and annual retail energy sales of 2,590 GWh or approximately 1.1 percent of Florida's annual retail energy sales. Figure 46 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, TAL's customer base has increased by 9.55 percent, while retail sales have increased by 0.13 percent.

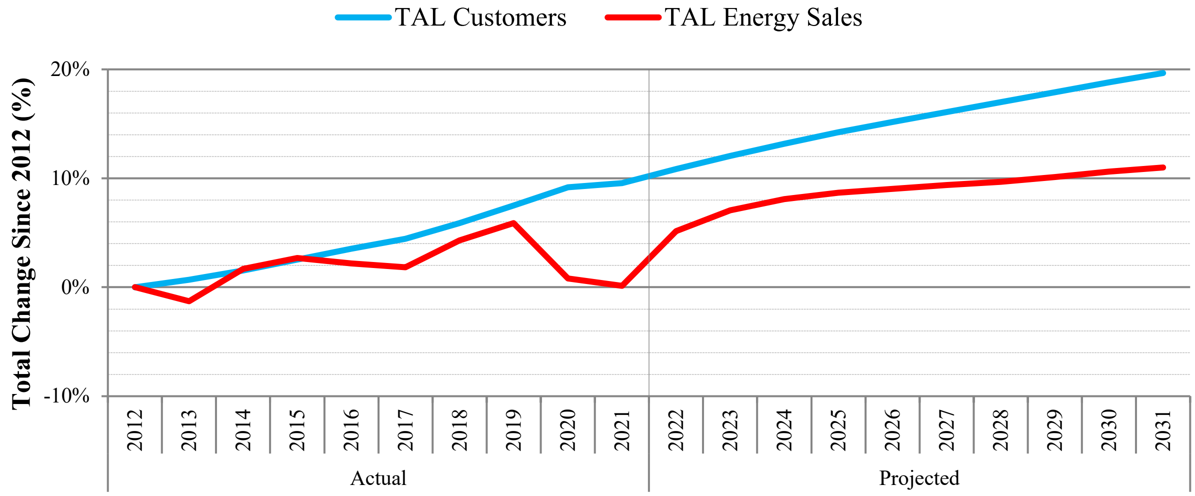
TAL's customer base consists of residential and commercial classes; and, the total energy consumption associated with the commercial class is higher than that associated with the residential class. Over the last decade, the utility's customer count growth has been robust. This growth correlates well to the rate of change in Leon County's population, household formation, and economic activity; such as, the increased rates of household counts, total employment and average real income per household. As a result of the expected continuation of favorable economic conditions in Leon County, TAL expects a continued strong growth in its customer counts.

The utility's residential electricity use per customer has been flattening after several years of decline. This is believed to be driven primarily from end-use efficiency standards that have been filtering into the stock of equipment through replacements and new builds. These end-use efficiency standards are believed to be nearly fully diffused into the current residential stock. Commercial energy use per customer has continued to decline it has been particularly impacted since early 2020 by COVID-19, from which certain large loads are still recovering.

TAL's load forecast reflects the continued impacts of energy efficiency standards and codes, as well as the utility's DSM and conservation/energy efficiency programs. These impacts are slightly offset by upward pressure on total residential consumption from increasing incomes, electric vehicle adoption, and other factors, resulting in essentially flat residential sales growth over the forecast horizon.

Over the current forecast horizon, TAL is projecting an average annual growth of 0.85 percent in its total customer counts, and a growth rate of 0.60 percent in its annual retail energy sales.

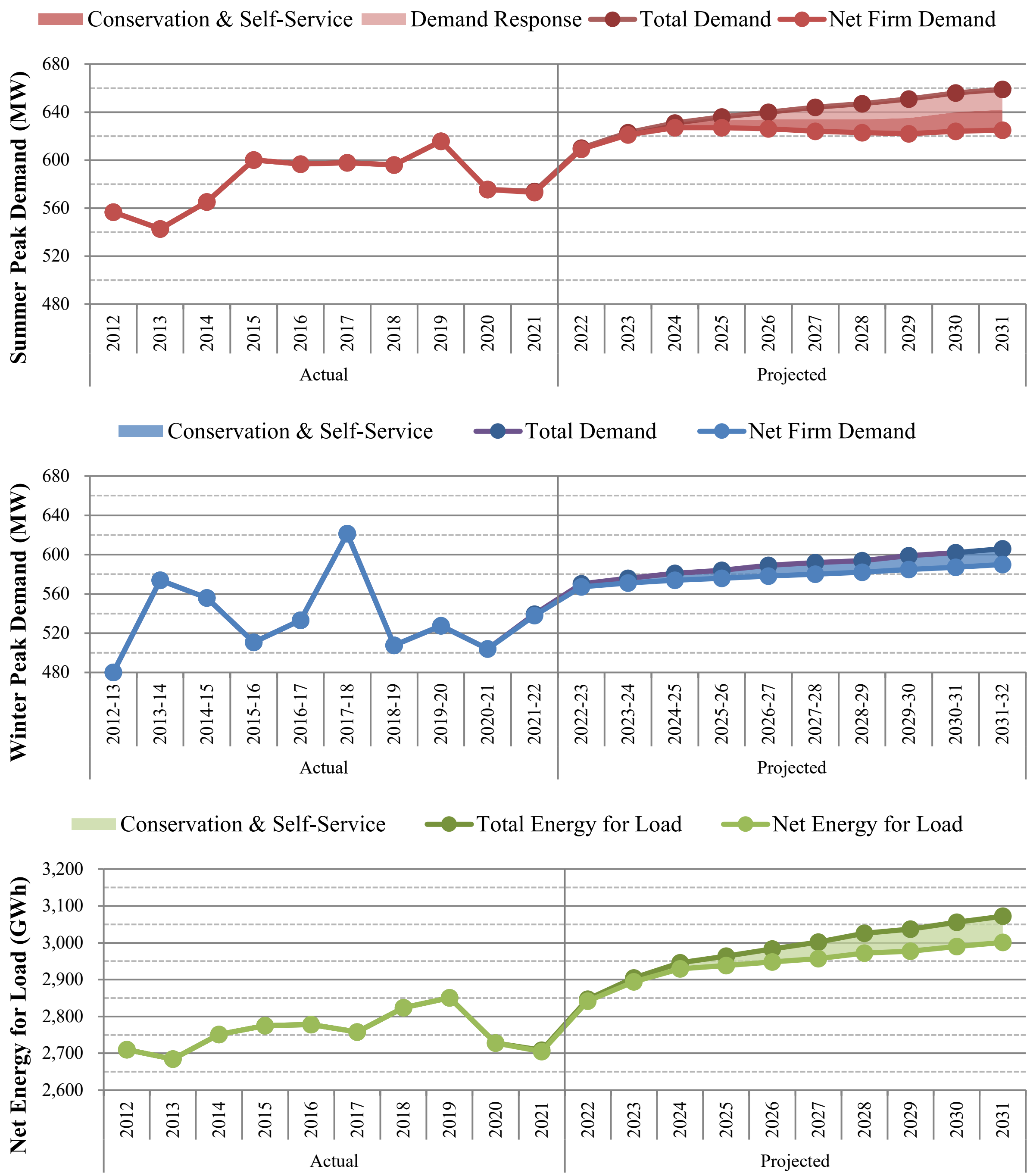
Figure 46: TAL Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 47 shows TAL's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently, TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 47: TAL Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 31 shows TAL's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities. Natural gas is anticipated to remain the primary fuel source on the system. TAL projects it will continue to be a net exporter of energy, primarily of off-peak power during shoulder months due to its generation's operating characteristics.

Table 31: TAL Energy Generation by Fuel Type

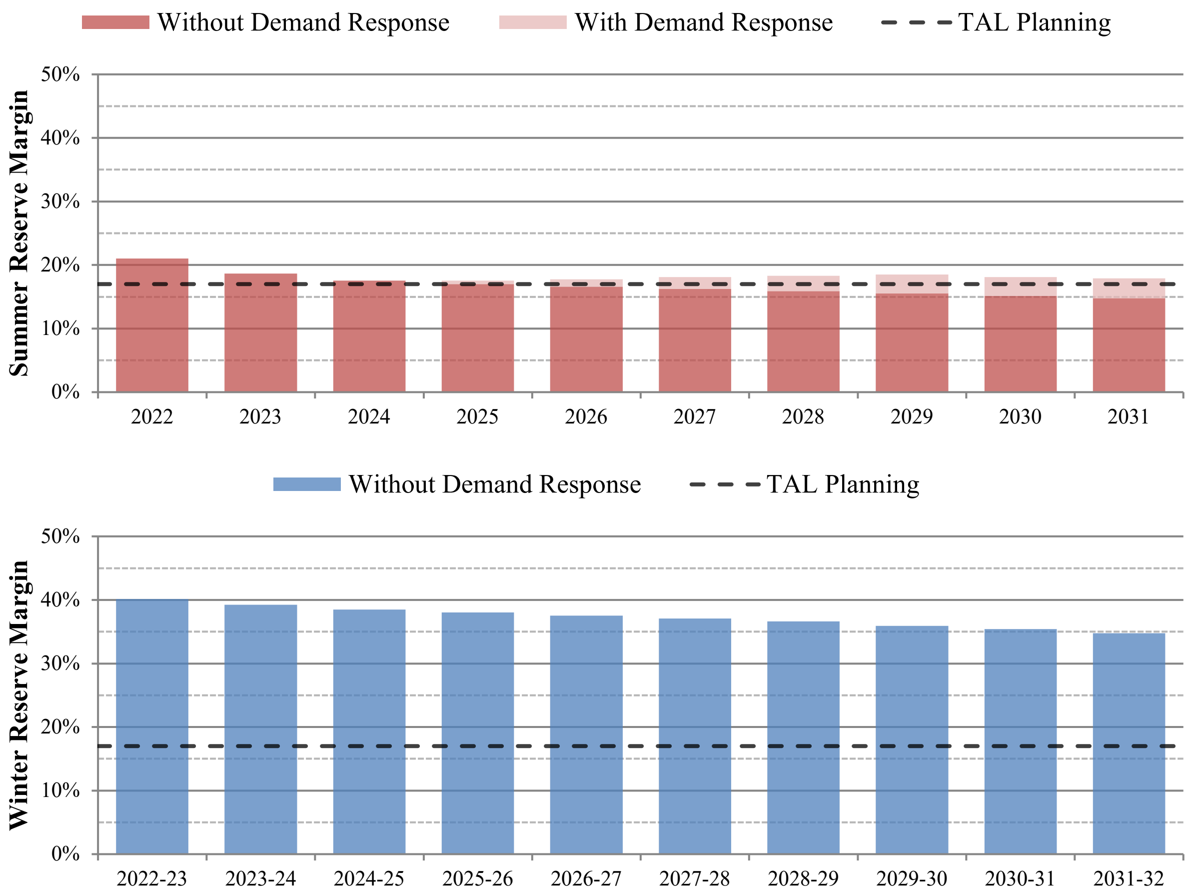
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	2666	**97.7%**	3,021	**101.2%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	113	**4.1%**	116	**3.9%**
Interchange	-51	**-1.9%**	(153)	**-5.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,729**		**2,985**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 48 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 48: TAL Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

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