I. Meeting Packet

State of Florida

Public Service Commission

INTERNAL AFFAIRS AGENDA

Thursday – December 19, 2024
9:30 AM
Room 105 – Gerald L. Gunter Building

1. Draft 2024 Ten-Year Site Plans of Florida Electric Utilities (Attachment 1)

2. Draft Plan to Assess the Physical and Cyber Security of Florida's Electric Grid and Natural Gas Facilities, as required by Chapter 2024-186, Laws of Florida (Attachment 2)

3. Legislative Update

4. General Counsel's Report

5. Executive Director's report

6. Other Matters

BB/aml

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

Attachment 1

State of Florida

Public Service Commission

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

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

DATE: December 12, 2024

TO: Braulio L. Baez, Executive Director

FROM: Greg Davis, Engineering Specialist III, Division of Engineering GD LK
Phillip O. Ellis, Public Utilities Supervisor, Division of Engineering POE TB

RE: Draft Review of the 2024 Ten-Year Site Plans of Florida's Electric Utilities

CRITICAL INFORMATION: Place on December 19, 2024 Internal Affairs Agenda. Approval by the Commission is required by December 31, 2024.

Pursuant to Section 186.801, Florida Statues, electric utilities are required to submit to the Commission a Ten-Year Site Plan which shall estimate a utility's power-generating needs and the general location of its proposed power plant sites. The Commission is required to make a preliminary study of each plan and classify it as "suitable" or "unsuitable" within nine months after receipt of the proposed plan. Electric utility plans were filed on April 1, 2024. Staff seeks approval of the attached revised draft report which incorporates an updated Executive Summary as directed by the Commission during the November 19, 2024 Internal Affairs meeting. .

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

GD:pz

Attachment

cc: Keith Hetrick, General Counsel
Mark Futrell, Deputy Executive Director – Technical
Apryl Lynn, Deputy Executive Director – Administrative

REVIEW OF THE

2024 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

DRAFT 12-12-2024

FLORIDA PUBLIC
SERVICE COMMISSION

DECEMBER 2024

Table of Contents

List of Figures

List of Tables

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 2024 Ten-Year Site Plans for Florida's electric utilities, filed by 10 reporting utilities.[1]

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

[1] Investor-owned utilities filing 2024 Ten-Year Site Plans include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2024 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 2024 Ten-Year Site Plan.

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

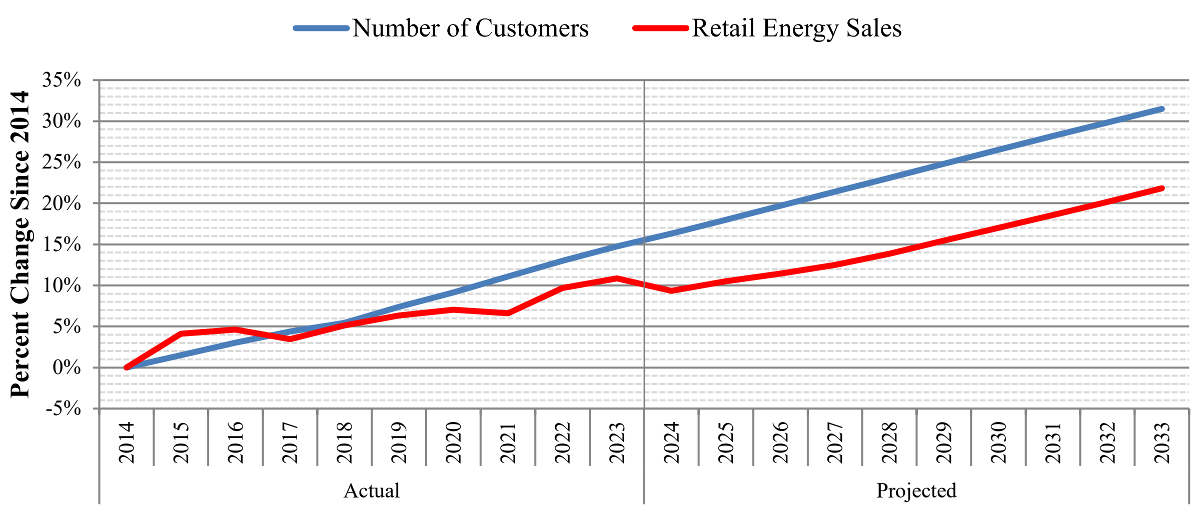
Review of the 2024 Ten-Year Site Plans

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. Forecasted retail energy sales in 2024 are lower than the actual retail energy sales in 2023. This is because of warmer weather conditions in 2023, and normalized weather trends were used to forecast 2024 through 2033.

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



Source: FRCC 2024 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 11,470 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 87 percent of Florida's existing renewables. Notably, Florida electric customers had installed 2,351 MW of demand-side renewable capacity by the end of 2023, an increase of 32 percent from 2022.

Florida's total renewable resources are expected to increase by an estimated 30,737 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase; however, only 8,007 MW of these new solar resources are considered as firm resources for summer peak 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 while having a lesser impact on system adequacy. Therefore, several utilities plan on adding battery storage totaling 5,305 MW during the planning period, which would increase firm capacity available during both seasonal system peaks.

Table 1 provides a breakdown of each TYSP Utility's actual 2023 and projected 2033 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 6.8 percent in 2023 to 30.8 percent in 2033.

Table 1: State of Florida - Renewable Energy Generation

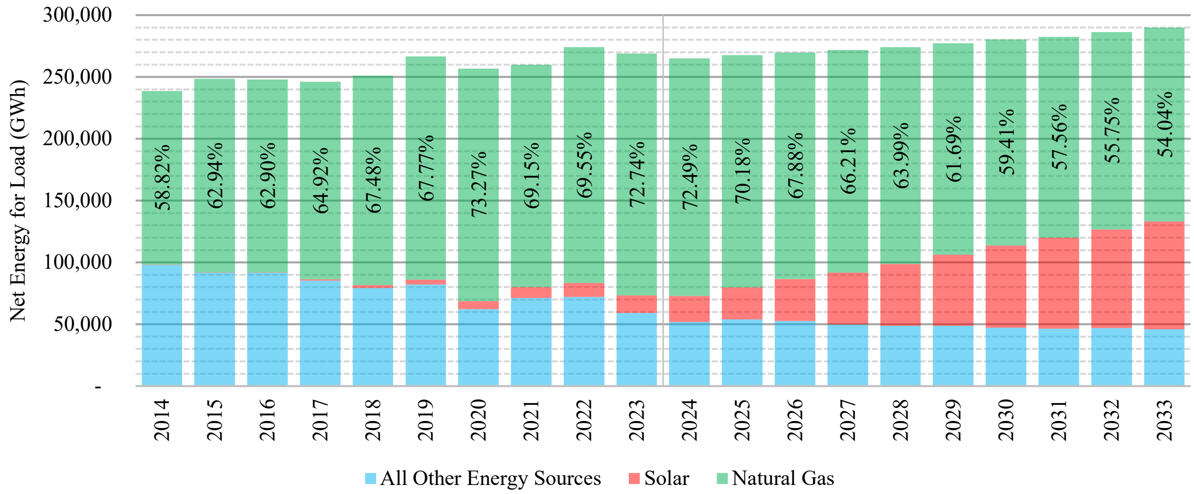
Utility	2023 Actual			2033 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL	140,464	10,217	7.27%	153,681	59,440	38.68%
DEF	44,046	2,788	6.33%	47,094	13,408	28.47%
TECO	21,767	1,748	8.03%	23,224	6,191	26.66%
FMPA	7,174	143	1.99%	6,766	647	9.56%
GRU	1,861	296	15.90%	1,972	640	32.45%
JEA	12,722	412	3.24%	13,885	3,146	22.66%
LAK	3,442	25	0.73%	3,670	178	4.85%
OUC	7,972	396	4.97%	8,994	4,513	50.18%
TAL	2,753	107	3.89%	2,856	111	3.89%
SEC	16,312	423	2.59%	19,484	738	3.79%
State	268,898	18,217	6.77%	289,894	89,303	30.81%

Source: FRCC 2024 Regional Load and Resource Plan and 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 2,159 MW of traditional generation over the planning horizon, with natural gas plant additions offset by coal and oil retirements. Natural gas electric generation, as a percent of NEL, is expected to decline from 70 percent in 2023 to 54 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 all other sources combined excluding natural gas by 2028.

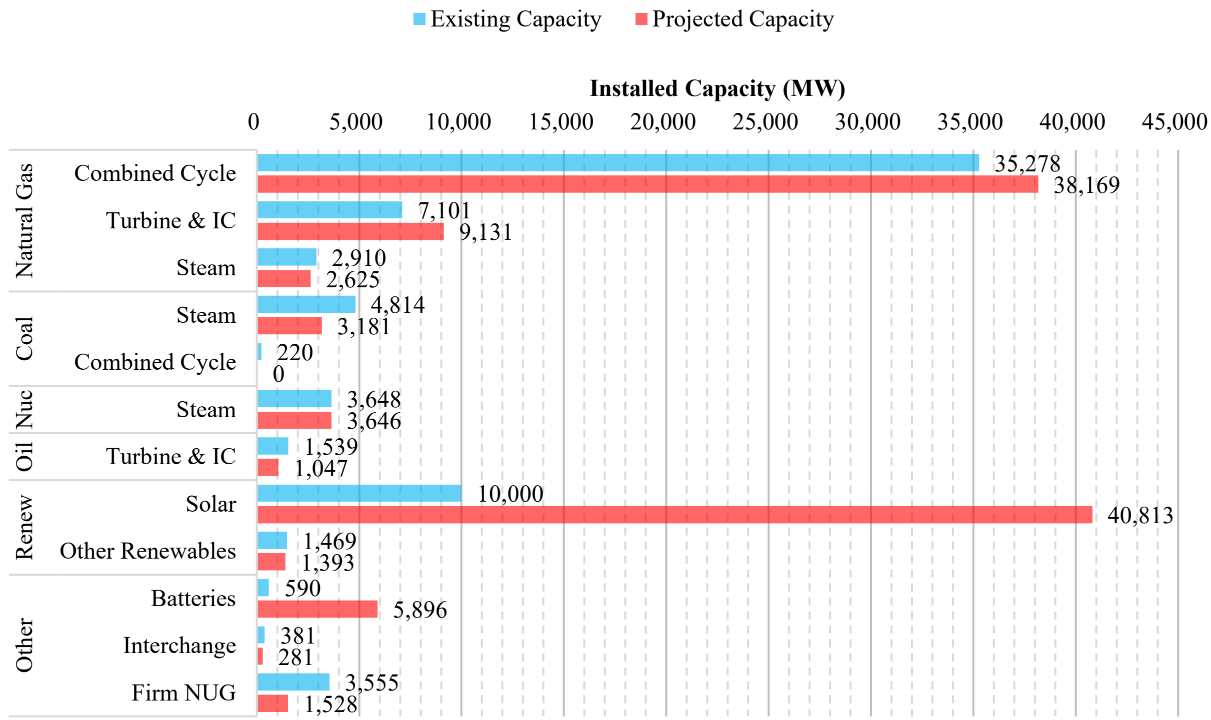
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2015-2024 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2024 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 already the second highest category of installed capacity, and will exceed natural gas combined cycle nameplate capacity by the end of the 10-year planning period. As mentioned previously, not all of the installed solar capacity provides a firm resource that is available to serve peak demand.

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



Source: FRCC 2024 Regional Load and Resource Plan and 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 two new units planned that may require a determination of need from the Commission pursuant to Section 403.519, F.S. JEA's TYSP includes a unit in 2030 and SEC's TYSP includes a unit in 2032.

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, on May 9, 2024, the EPA released a final rule consisting of five separate actions under the Clean Air Act (CAA) Section 111, targeting greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). These and other relevant EPA actions are further discussed in the Traditional Generation section.

Emerging Trends

In addition to changes in regulations, the electric utilities must also maintain an awareness of emerging trends in energy consumption and generation technologies, and their impacts on the industry. Trends, such as customer adoption of EVs, the potential for growth of data centers due to applications such as artificial intelligence, solar technologies, energy storage, and grid resilience, are important for the electric utilities to track both to determine future impacts and the best way to address them. One such area is advanced nuclear power technologies, such as small modular reactors. As directed by House Bill 1645, the Commission will be submitting a report evaluating the technical and economic feasibility of using these technologies, and recommendations to enhance nuclear technologies by April 1, 2025. While the information on these trends is limited in this Review of the Ten-Year Site Plans, the Commission will continue to monitor these trends and their impacts as they are included within the electric utilities' Ten-Year Site Plans each year.

Conclusion

The Commission has reviewed the 2024 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 2024 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.

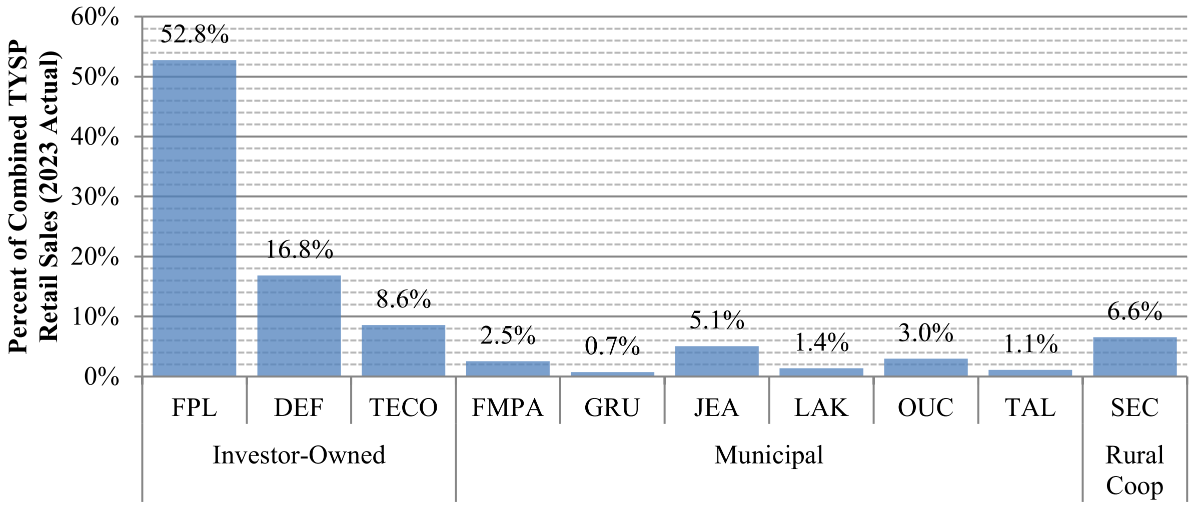
Applicable Utilities

Florida is served by 57 electric utilities, including 4 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only electric utilities with an existing generating 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 2024, 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 2024 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 combined TYSP Utilities' retail energy sales in 2023. Collectively, the reporting investor-owned utilities account for 78.2 percent of the reported retail energy sales, while the municipal and cooperative utilities make up approximately 20.3 percent of the reported retail energy sales.

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



Source: FRCC 2024 Regional Load and Resource Plan and 2024 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 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.

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' 2024 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

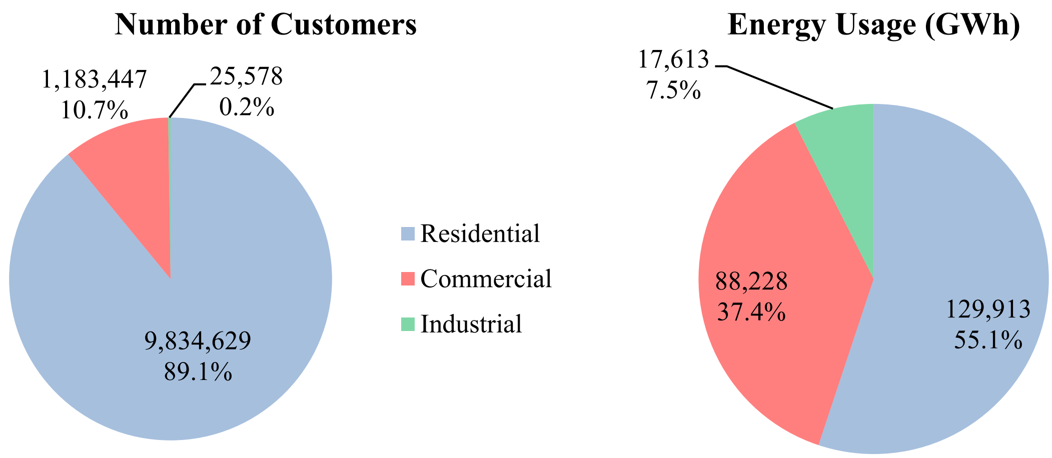
Load Forecasting

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 illustrated in Figure 5, residential customers account for 89.1 percent of the total, followed by commercial (10.7 percent) and industrial (0.2 percent) customers. 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 2023



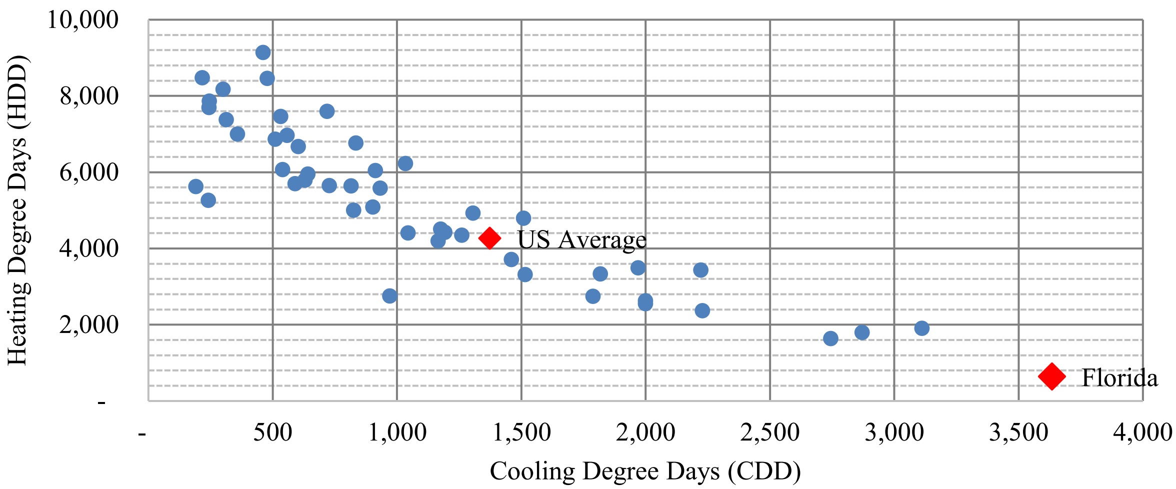
Source: FRCC 2024 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55.1 percent of retail energy sales in 2023, compared to a national average of approximately 38.4 percent in 2022.[3] 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

[3] U.S. Energy Information Administration – Sales and Direct Use of Electricity to Ultimate Customers.

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 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)



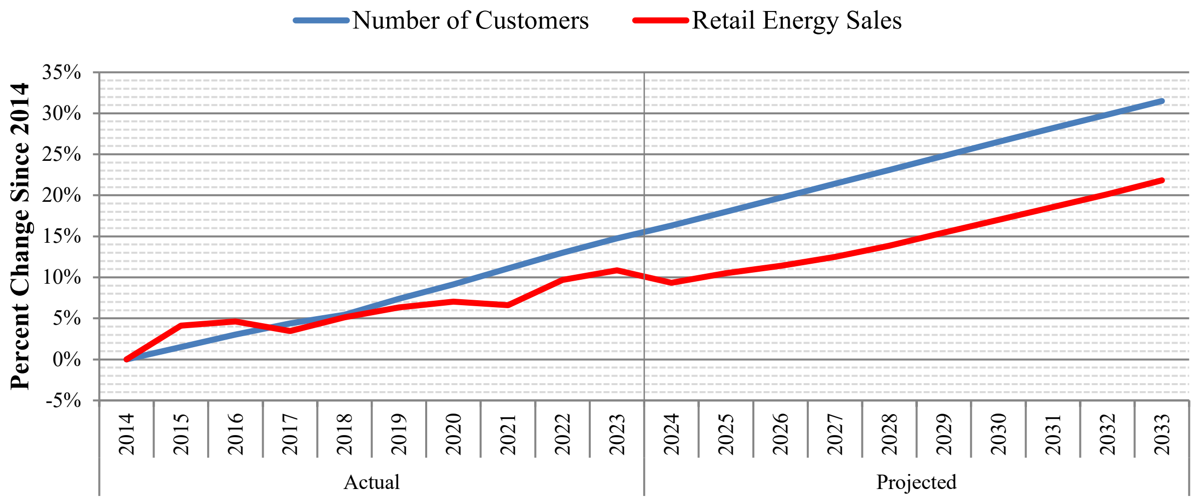
Source: National Oceanic and Atmospheric Administration Data

Growth Projections

For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.21 percent per year, compared to the 1.15 percent actual annual increase experienced during the 2014-2023 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.37 percent for the next 10-year period, compared to the 1.54 percent actual annual increase experienced during the last decade. These trends are showcased in Figure 7.

As shown in Figure 7, Florida utilities' total retail energy sales reached a historical peak in 2023 surpassing the most recent peak that was reached in 2020. Several factors converged to contribute to this effect: continued growth in the number of retail customers as more people move into the state, warmer than normal weather conditions, and a surge in economic activity in the state's vibrant tourism and service sectors as they further recover from the COVID-19 pandemic, which leads to increased electricity consumption across various industries. The second highest peak in energy sales occurred in 2020, which was mainly a result of residential customers working or schooling from home during the pandemic. Florida utilities' total retail energy sales are projected to continuously grow at a moderate annual average rate for the next 10 years. This sales growth is driven by an anticipated growth in customers and business activity, as well as the expected increased level of adoption of electric vehicles.

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



Source: FRCC 2024 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.

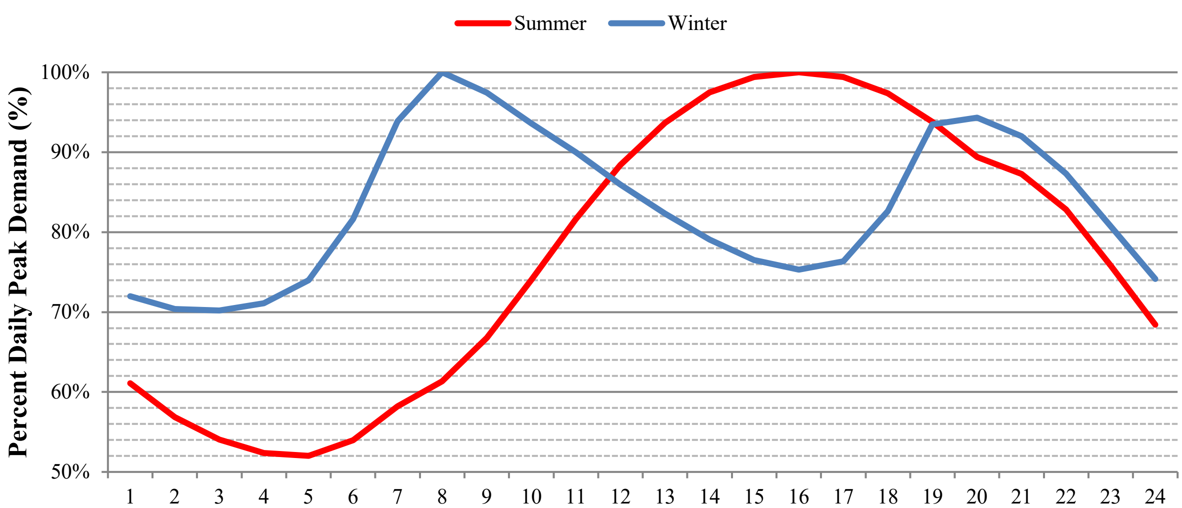
With respect to the energy consumption per customer forecasts, FPL forecasted that its residential use per customer will be flat or slightly grow (as high as 0.4 percent on average) due to economic growth as well as increased adoptions of electric vehicles. The utility expects that its commercial use per customer will decline between 0.1 to 0.7 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, more stringent building codes, housing type/size, and space conditioning equipment energy source. 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, DEF also noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal. 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 in new homes, conservation efforts and changes of its customer 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 technologies for energy efficiency, renewable generation, and alternative energy sources, with some utilities expecting that the increased electric vehicle charging will mitigate this downward pressure to some extent.

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

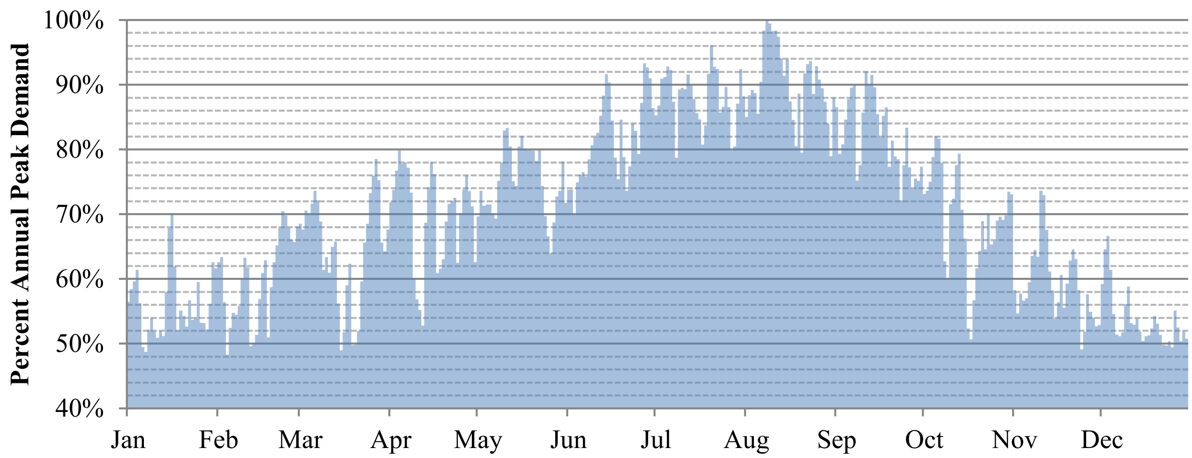


Source: TYSP Utilities' Data Responses

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 2023 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 (2023 Actual)



Source: 2024 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

Other trends that may impact customer peak demand and energy consumption are also examined by utilities, including new sources of energy consumption, such as electric vehicles (EVs). The reporting TYSP Utilities estimate approximately 428,607 electric plug-in vehicles will be operating in Florida by the end of 2024. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 7, 2024 at 18.64 million vehicles, resulting in an approximate 2.30 percent penetration rate of electric vehicles, up from 1.52 percent last year.[4]

TYSP Utilities responded to a data request regarding projections of electric vehicle ownership, public charging stations, and impacts to their electric grid, and the details appear in Tables 2 through 5. As it relates to the responses received, OUC did not provide projections of EVs,

[4] Florida Department of Highway Safety and Motor Vehicles January 2024 Vehicle and Vessel Reports and Statistics.

charging stations, or EV demand/energy. Florida's retail 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 4,312,553 EVs operating within the reporting utilities' electric service territories by the end of 2033.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	293,845	68,488	47,374	13,467	1,812	1,844	1,777	428,607
2025	428,132	104,185	67,251	16,526	2,226	2,379	2,220	622,919
2026	590,749	157,228	89,559	19,881	2,690	2,983	2,727	865,817
2027	787,129	234,412	114,145	23,577	3,211	3,650	3,331	1,169,455
2028	1,018,957	339,524	140,948	27,665	3,793	4,382	3,990	1,539,259
2029	1,287,414	474,718	169,854	32,169	4,440	5,183	4,731	1,978,509
2030	1,589,148	636,557	200,304	37,114	5,159	6,024	5,568	2,479,874
2031	1,929,264	822,895	231,346	42,493	5,951	6,873	6,442	3,045,264
2032	2,300,764	1,029,188	263,294	48,347	6,824	7,735	7,467	3,663,619
2033	2,695,021	1,242,094	295,772	54,689	7,781	8,595	8,601	4,312,553

Source: TYSP Utilities' Data Responses

The major drivers of EV 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. 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 EVs as well as to promote electric vehicle ownership.

Table 3 illustrates the reporting electric utilities' projections of public EV charging stations through 2033. While approximately 16,000 charging stations are estimated to be available across the state by the end of 2024, more than 136,000 charging stations are anticipated by 2033. The estimated EV charging station counts listed in Table 3 include both normal and "quick-charge" public charging stations.[5]

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

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

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	12,770	1,905	710	200	94	25	135	15,839
2025	20,601	2,498	810	232	148	30	136	24,455
2026	29,392	3,246	916	266	179	40	137	34,176
2027	38,516	4,209	1,028	302	214	50	139	44,458
2028	48,807	5,395	1,147	341	253	55	140	56,138
2029	60,490	6,819	1,272	384	296	60	141	69,462
2030	72,659	8,450	1,404	430	344	65	142	83,494
2031	86,389	10,311	1,542	479	397	70	143	99,331
2032	100,511	12,397	1,687	532	455	75	145	115,802
2033	118,956	14,574	1,838	589	519	80	147	136,703

Source: TYSP Utilities' Data Responses

Table 4 illustrates the TYSP Utilities' projections of energy consumed by EVs through 2033. Across the TYSP Utilities, anticipated growth would result in an annual energy consumption of 14,862.4 GWh by 2033, which represents an impact of approximately 5.2 percent of net energy for load.[6]

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

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	351.5	49.6	263.8	45.5	8.7	1.5	2.6	723.1
2025	816.1	143.2	352.8	58.2	10.7	1.5	3.5	1,386.0
2026	1,387.8	285.6	454.2	72.2	12.9	2.9	4.7	2,220.4
2027	2,092.6	496.1	564.9	87.6	15.4	4.4	6.3	3,267.4
2028	2,945.3	791.7	683.2	104.7	18.2	4.4	8.8	4,556.2
2029	3,957.4	1,182.5	810.4	123.5	21.3	4.4	12.0	6,111.4
2030	5,123.6	1,662.6	944.2	144.2	24.8	7.3	15.8	7,922.4
2031	6,523.6	2,220.8	1,080.8	166.8	28.6	7.3	20.0	10,047.9
2032	8,117.9	2,845.7	1,221.9	191.3	32.8	8.8	24.9	12,443.2
2033	9,696.5	3,506.0	1,365.5	218.0	37.3	8.8	30.3	14,862.4

Source: TYSP Utilities' Data Responses

Table 5 illustrates the TYSP Utilities' estimates of the effects of EV ownership on summer and winter peak demand through 2033. Across the TYSP Utilities, anticipated growth results in an impact to summer peak demand of approximately 3,503.4 MW and an impact to winter peak demand of approximately 1,319.6 MW by 2033. Current estimates represent a cumulative impact

[6] Estimate assumes a state-wide net energy for load of approximately 285,404 GWH by 2033, as discussed later in the Forecast Load and Peak Demand section of this TYSP.

of approximately 6.3 percent on summer peak demand and a 2.6 percent on winter peak demand by 2032.[7]

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

Summer Peak Demand (MW)

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	86.3	13.7	50.1	3.9	7.7	1.0	0.5	163.3
2025	200.5	33.6	66.3	5.0	9.2	1.0	0.7	316.3
2026	340.9	63.0	84.9	6.2	11.0	2.0	0.9	508.9
2027	514.0	105.6	105.0	7.5	13.1	3.0	1.2	749.5
2028	723.5	164.1	126.5	9.0	15.5	3.0	1.7	1,043.3
2029	972.1	293.4	149.6	10.6	18.1	3.0	2.3	1,449.1
2030	1258.5	331.4	173.8	12.4	21.1	5.0	3.1	1,805.2
2031	1602.4	531.1	198.5	14.3	24.3	5.0	3.9	2,379.6
2032	1994.0	668.6	224.1	16.4	27.9	6.0	4.8	2,941.8
2033	2381.8	809.1	250.1	18.7	31.8	6.0	5.9	3,503.4

Winter Peak Demand (MW)

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	37.3	0.4	16.8	1.0	7.7	1.0	0.1	64.3
2025	86.7	3.4	21.3	1.3	9.2	1.0	0.1	123.1
2026	147.4	8.3	26.9	1.6	11.0	2.0	0.2	197.5
2027	222.3	16.0	32.7	2.0	13.1	3.0	0.3	289.4
2028	312.9	27.8	38.8	2.3	15.5	3.0	0.5	400.9
2029	420.5	44.6	45.3	2.8	18.1	3.0	0.6	534.8
2030	544.4	67.4	52.0	3.2	21.1	5.0	0.9	694.0
2031	693.1	96.0	58.9	3.7	24.3	5.0	1.2	882.3
2032	862.5	130.9	66.1	4.3	27.9	6.0	1.5	1,099.2
2033	1030.2	171.4	73.4	4.9	31.8	6.0	1.9	1,319.6

Source: TYSP Utilities' Data Responses

In order to prepare for and to accommodate the inevitable increase in EV ownership, several utilities now offer programs or tariffs applicable to EV customers. While the nature of these programs/tariffs vary among utilities, many include Time-of-Use (TOU) rates, rebates on certain

[7] Estimate assumes a state-wide net firm summer peak demand of approximately 55,956 MW and a net firm winter peak demand of approximately 51,076 MW by 2033, as discussed later in the Forecast Load and Peak Demand section of this TYSP.

charging station installations, and programs designed to increase general outreach, education, and awareness of the EV market.

In addition to the increase in general outreach, etc. for EV market awareness and education, some utilities currently operate specific EV pilot programs in order to investigate potential unknowns associated with the market. These programs have been established either as independently initiated programs or as part of rate case settlement agreements. Most of the programs are multi-year pilot programs which include extensive investments in electric vehicle charging infrastructure and market research. EV Pilot programs serve to provide the utilities insight for assessment as to whether such programs/tariffs should be continued, expanded, made permanent, or discontinued. These pilot programs also provide the Commission with valuable information, such as individual charging session data, peak EV charging hours, and impacts to peak demand - via annual updates from the utilities with regard to their respective pilot programs. The Commission will continue to closely monitor the key findings and metrics of interest within these pilot programs in order to be prepared to address any regulatory issues associated with the future energy and demand impacts of electric vehicles in Florida.

Demand-Side Management (DSM)

Florida's electric utilities also consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include: turning off lights and fans in vacant rooms, increasing thermostat settings 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 86.2 percent of 2023 retail electric sales reported by the TYSP Utilities.

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.

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[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.

In 2024, the Commission held a hearing and established goals for each of the FEECA Utilities for the period 2025 through 2034. Each FEECA electric utility will be required to submit a proposed DSM Plan, designed to meet its goals within 90 days of the final order establishing the goals. These proceedings are anticipated to be completed during 2025. The Commission is scheduled to have its next goalsetting proceeding no later than 2029 for the period 2030 through 2039.

DSM Programs

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

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

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak. As of 2024, the total amount of demand response resources available for reduction of peak load is 3,151 MW for summer peak and 2,965 MW for winter peak. Demand response is anticipated to decline to approximately 3,082 MW for summer peak and 2,937 MW for winter peak by 2033. Residential load management is anticipated to decline slightly, while interruptible load is level and commercial/industrial demand response has a slight increase.

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, 2023, energy efficiency is responsible for peak load reductions of 4,617 MW for summer peak and 4,084 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,967 MW for summer peak and 5,235 MW for winter peak by 2033.

Forecast Load and 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. Forecasted net energy for load in 2024 is lower than the actual net energy for load in 2023. This is because of warmer weather conditions in 2023, and normalized weather trends were used to forecast 2024 through 2033.

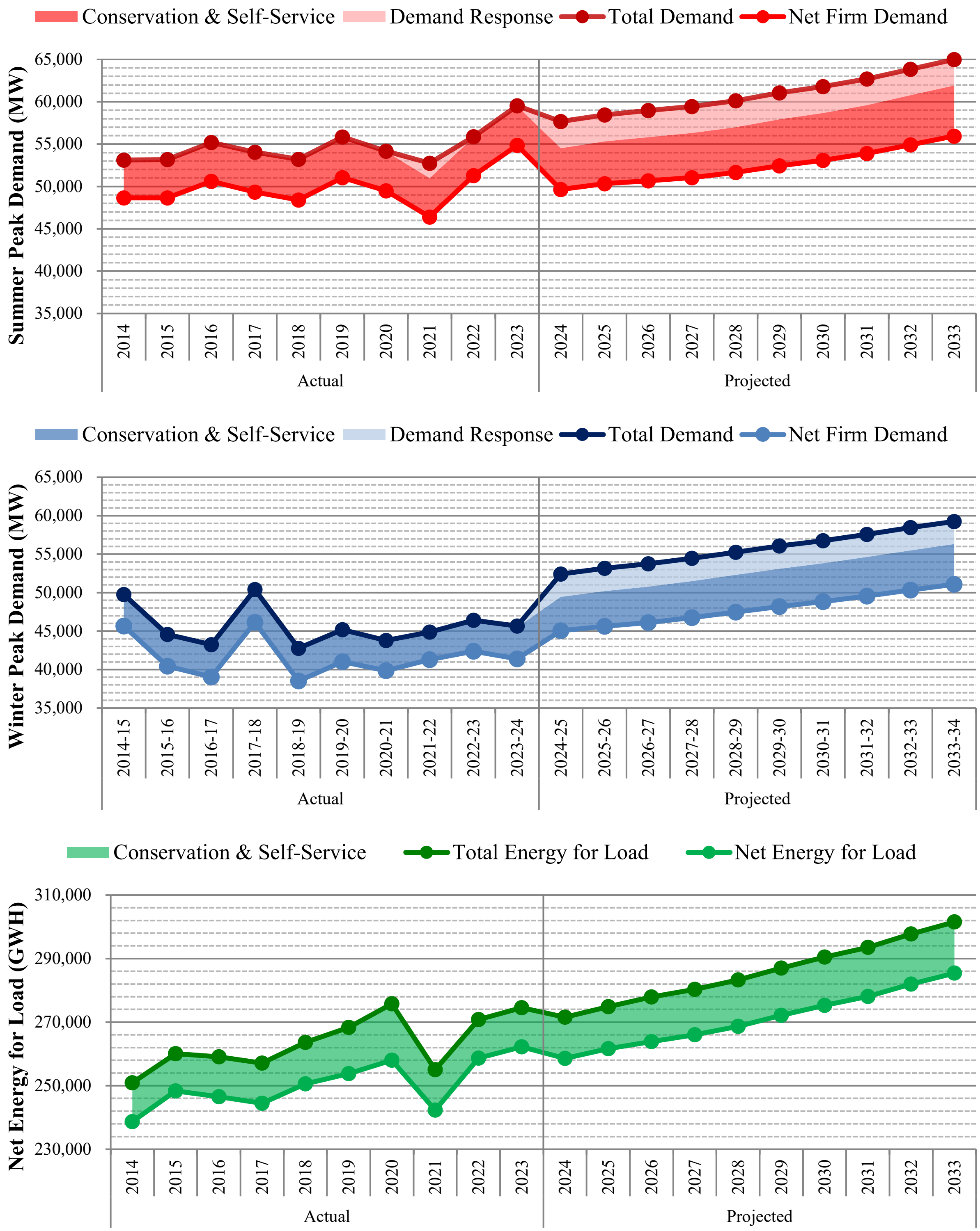
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served 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 2024 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 balance 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 (TYSP).

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 and summer peak demand per customer, residential energy use per customer) and independent variables (e.g., peak day minimum temperature, real personal income, heating degree days and cooling degree days, 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' specific expectations for their own future electricity consumption.

Forecasting models for energy sales 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. The forecasting models for energy sales must also take into account demand-side management.

Another type of forecasting model, sometimes used to project energy use in conjunction with econometric models, is an "end-use model." 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 project load. The models have relied upon dependent and independent variable data to project energy sales 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 for the 2024 TYSPs, 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 energy sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2023 retail energy sales were compared to the forecasts made in 2018, 2019, and 2020. The resulting 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 2024 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2014 through 2023 to forecasts made between 2005 and 2020. 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
2014	2014 - 2010	2011 - 2005	14.95%	14.95%
2015	2015 - 2011	2012 - 2006	12.48%	12.48%
2016	2016 - 2012	2013 - 2007	9.11%	9.11%
2017	2017 - 2013	2014 - 2008	5.96%	5.96%
2018	2018 - 2014	2015 - 2009	3.47%	3.47%
2019	2019 - 2015	2016 - 2010	2.13%	2.32%
2020	2020 - 2016	2017 - 2011	1.58%	2.04%
2021	2021 - 2017	2018 - 2012	1.04%	1.61%
2022	2022 - 2018	2019 - 2013	-0.13%	1.36%
2023	2023 - 2019	2020 - 2014	-1.02%	1.59%

Source: 2005-2024 Ten-Year Site Plans
* Inputs used including utilities' revisions to the corresponding prior TYSP-reported actual and/or projected data.

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 2012 through 2015. 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 2012-2014 sales forecasts. Most of the last four years' four-year ahead forecasts and the last five years' three-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, the last six years' two-year ahead forecasts and one-year ahead forecasts render negative error rates as well. Note that all of the 2022- and 2023-related forecasts made between one to six years prior show relatively higher negative error rates. This is due to the respective annual retail energy sales achieved which is largely attributable to the very hot weather Florida experienced in 2022 and 2023.

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		
2012	26.43%	26.12%	23.16%	8.58%	4.01%	3.81%	19.29%	19.29%
2013	28.58%	26.29%	10.00%	5.98%	5.58%	2.97%	14.09%	14.09%
2014	27.15%	9.69%	6.00%	5.62%	2.73%	2.11%	7.10%	7.10%
2015	7.18%	3.53%	3.13%	0.92%	-0.10%	-1.27%	2.52%	2.52%
2016	4.22%	4.27%	2.18%	1.14%	0.10%	-1.07%	2.53%	2.53%
2017	6.87%	4.82%	3.48%	2.42%	1.45%	-0.18%	3.57%	3.57%
2018	4.16%	2.65%	1.64%	0.64%	-1.25%	-1.19%	1.64%	1.64%
2019	2.77%	1.86%	0.75%	-1.40%	-1.42%	-2.03%	0.40%	1.34%
2020	2.44%	1.27%	-0.97%	-1.07%	-1.91%	-1.22%	-0.25%	1.10%
2021	2.58%	0.35%	0.02%	-0.80%	-0.05%	0.03%	-0.15%	0.39%
2022	-1.60%	-1.87%	-2.85%	-2.23%	-2.13%	-3.06%	-2.32%	2.32%
2023	-2.09%	-3.27%	-2.68%	-2.45%	-3.16%	-2.63%	-2.80%	2.80%

Source: 2005-2024 Ten-Year Site Plans
*Inputs used include utilities' revisions to the corresponding prior TYSP-reported actual and/or projected sales data.

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 2022 in Table 7. However, all the major global and domestic events (e.g., the Russo-Ukrainian War, pandemic, supply chain issues, high inflation rates, potential recession, etc.), individually or collectively, could inflict damage to the US economy. As such, there remains uncertainty as to what the economic impacts of such events will be going forward. Therefore, the actual retail energy sales of the next few years could be different from what Florida utilities projected in 2023 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 even global health, political and economic issues present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of retail 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 11,470 MW of firm and non-firm generation capacity, which represents 16 percent of Florida's overall generation capacity of 71,505 MW in 2023. 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	10,000	87.2%
Municipal Solid Waste	473	4.1%
Biomass	380	3.3%
Waste Heat	227	2.0%
Wind	272	2.4%
Landfill Gas	67	0.6%
Hydroelectric	51	0.4%
Renewable Total	**11,470**	100.0%

Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Of the total 11,470 MW of renewable generation, approximately 3,937 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 3,499 MW to this total, based upon the coincidence of solar generation and summer peak demand, or about 34 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 1,470 MW of non-solar generation, only 438 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, including 7,410 MW of installed 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 7,254 MW of existing utility-owned solar capacity, approximately 3,628 MW, or about 48 percent, is considered firm. All other renewable sources account for an additional 157 MW of utility-owned generation.

Non-Utility Renewable Generation

Approximately 4,059 MW, or 35 percent of Florida's existing renewable capacity is not owned by utilities, either from large supply-side non-utility generators or small distributed customer owned generation. Approximately 1,708 MW of that comes from supply side resources from non-utility generators such as cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA), which requires utilities to purchase electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

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

If a renewable energy generator can meet certain deliverability requirements, its capacity and energy output can be paid for under a firm contract. Rule 25-17.250, F.A.C., requires each investor-owned utility 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 investor-owned utilities 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 2,351 MW, or 21 percent of existing renewable capacity is from customer-owned systems, also referred to as demand-side renewable systems. Rule 25-6.065, F.A.C., requires the investor-owned utilities 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 2023, approximately 2,351 MW of renewable capacity from over 249,521 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 28 installations and 7 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	2017	2018	2019	2020	2021	2022	2023
Number of Installations	24,166	37,862	59,508	90,552	103,947	189,952	249,521
Installed Capacity (MW)	205	317	514	835	1,177	1,780	2,351

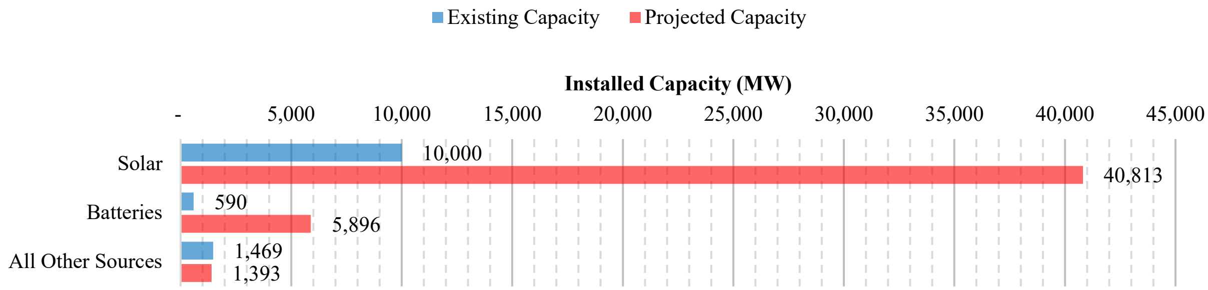
Source: 2017-2024 Net Metering Reports

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 30,737 MW over the 10-year planning period, an increase from last year's estimated 27,630 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type as well as energy storage capacity in the form of batteries. Solar generation, primarily utility-owned, is the sole renewable type projected to increase over the planning horizon. While solar generation is covered under the Power Plant Siting Act, all future solar projects are below the 75 MW threshold, and therefore are not required to seek approval from the Commission prior to construction.

Of the 30,737 MW projected net increase in renewable capacity, firm resources contribute 4,351 MW, or about 14 percent, of the total. This net increase value takes into account that for some existing renewable facilities are retired or contracts for firm capacity are projected to expire within the 10-year planning horizon, decreasing renewable capacity by 76 MW. 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.

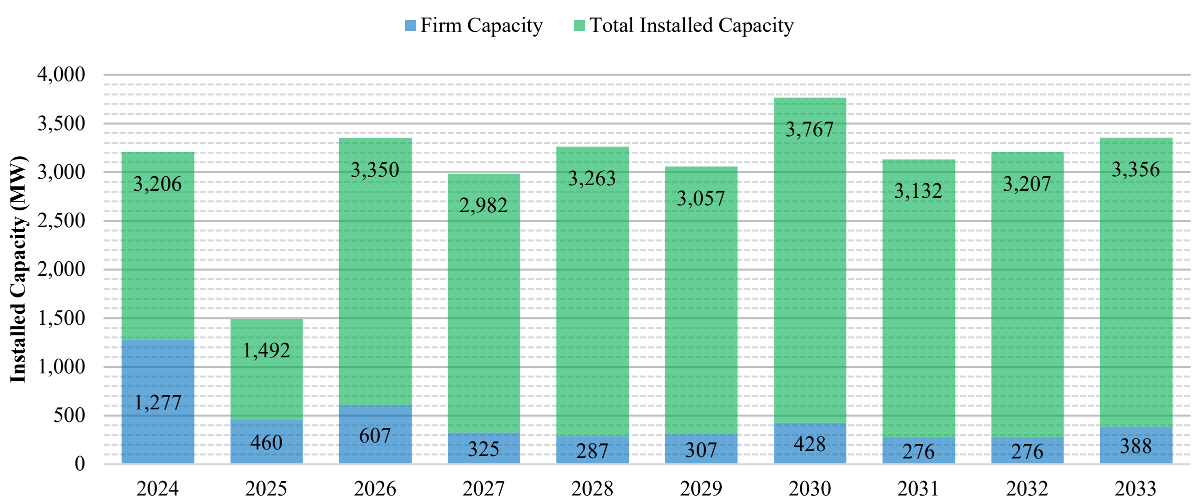
Figure 11: State of Florida - Current and Projected Renewable Resources



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 30,813 MW to be installed. This consists of 27,366 MW of utility-owned solar and 3,447 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.

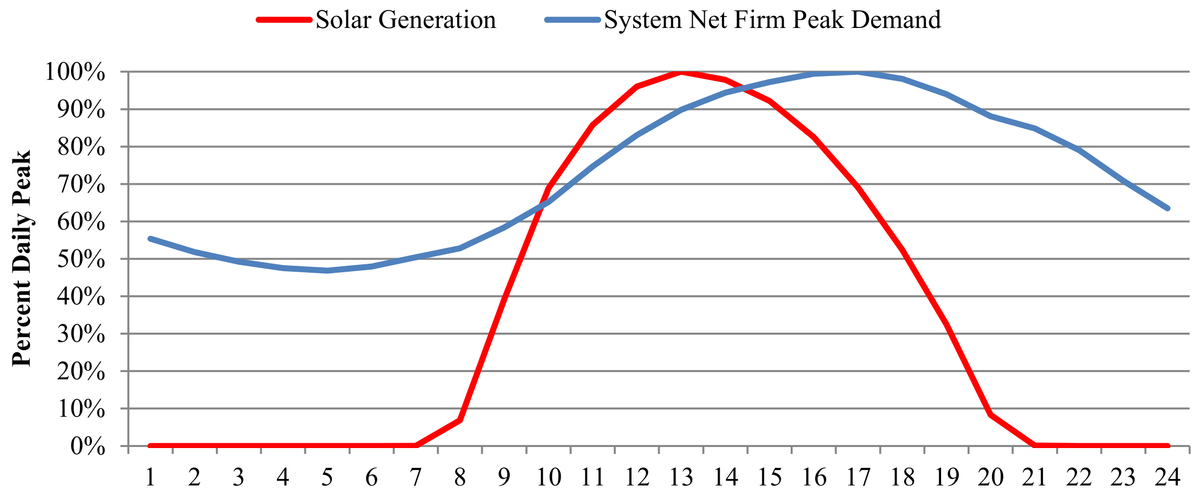
Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As the amount of solar increases in the state, the difference in how it operates compared to traditional generation will have an increasing importance to the grid. Solar generation cannot be dispatched as needed, but is produced based upon the conditions at the plant site, influenced by variations in daylight hours, cloud cover, and other environmental factors. Generally speaking, the peak hours for production of a solar facility are closer to noon, whereas the peak in system demand tends to be in the early evening in summer and early morning in winter. Figure 13 illustrates this with example data from FPL's 2023 TYSP hourly dispatch model for their 2024 summer peak day. While solar generation peaks at 1:00 p.m., the net firm system demand peaks at 5:00 p.m., when solar generation is only at 69 percent of its daily peak. By 6:00 p.m., demand remains high, at 98 percent of its daily peak, while solar generation falls to 52 percent. Energy storage and other technologies to shift load, such as demand-side management programs or demand response, can be used to offset these characteristics.

Figure 13: FPL 2024 Summer Peak Day Hourly Dispatch



Source: 2023 FPL Data Response

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, battery storage is primarily planned and used by utility companies. Battery storage has been proposed to be connected directly to the grid, behind the meter box (net metering) or connected directly to a Solar/PV unit. Battery storage technology has continued to advance, and the cost of storage is projected to continue to decline over the long-term, aided, in part, by continued tax credits from the Inflation Reduction Act.

Currently, Florida's utilities have primarily engaged in small pilot programs to determine the best placement and usage for energy storage technologies, including behind the customer's meter, at distribution substations, and at generating facilities. Each use case has its own benefits, to allow customers to ride out outages (net metering), improve reliability and decrease line losses (distribution substations), or provide firm capacity to the grid (at generating facilities). Currently, the TYSP Utilities have 590 MW of installed energy storage, primarily batteries, with the single largest installation being FPL's 409 MW Manatee battery storage site.

Over the next decade, utilities are anticipating adding approximately 5,305 MW of energy storage, primarily directly on the transmission system or connected to a specific power plant. While energy storage is discussed here within the context of renewables, as they provide firming for intermittent solar facilities, grid connected batteries will not be restricted to charging from renewable sources. These units can be charged using any source during off-peak periods, either from solar or fossil generation. To the extent solar generation is charging batteries it is also not offsetting fossil generation that otherwise would be occurring on the grid during the same period. Some energy storage will be directly connected to a specific renewable power plant however. For example, DEF will be constructing combined solar and energy storage systems, with 40 MW of planned energy storage capacity per 74.9 MW solar site. As these systems are associated with a particular facility, the improved firm contribution has already been included in the prior discussion regarding solar firm capacity.

Traditional Generation

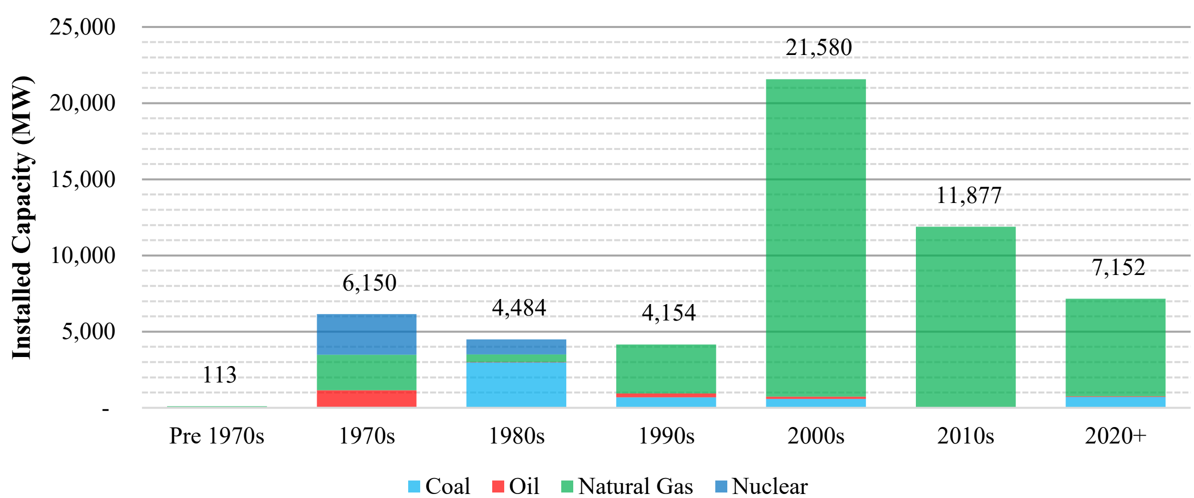
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. 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 traditional generating units is 21 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 14 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 14: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2024 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

On April 24, 2024, the EPA published the final rule, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants. Section 111 of the CAA directed the EPA to determine the best system of emission reduction (BSER), determine the degree of emission limitation achievable through the application of that system, and impose an emissions limit on new stationary sources that reflected that amount.

For existing coal-fired units, the final EPA rule identifies three subcategories based on how far into the future these plants plan to operate. Plants that plan to permanently cease operation prior to January 1, 2032, have no emission reduction guidelines under the final ruling. Plants that plan to cease operation by January 1, 2039, will be assigned a numeric emission rate limit based on 40 percent natural gas co-firing that they must meet by January 1, 2030. Plants that plan to operate past January 1, 2039, will be assigned a numeric emission rate limit based on application of carbon capture and sequestration (CCS) with 90 percent capture that must be met by January 1, 2032.

For new combustion turbines, the final rule establishes three subcategories based on how intensively they are operated: baseload, intermediate load, and low load. Baseload is defined as units with a capacity factor of at least 40 percent. Compliance for new base load turbines is broken down into two phases. Phase One includes highly efficient generation. Phase Two requires utilization of CCS with 90 percent capture by January 1, 2032. Intermediate load is defined as units with a capacity factor between 20 to 40 percent. For new intermediate load turbines, the BSER has been identified as highly efficient simple cycle generation. Low load is defined as units with a capacity factor less than 20 percent (peaking units). For new low load turbines, the BSER is the use of lower-emitting fuels.

Prior to the final rule, the EPA had published a proposed rule on May 11, 2023. Perhaps the most controversial aspect of the proposed rule dealt with emission standards for existing natural gas EGUs. However, in the final rule the EPA has declined to impose emission standards on existing natural gas power plants at this time.

The final rule has relied solely on a BSER of CCS for existing coal and new baseload natural gas EGUs. CCS has not been sufficiently demonstrated to be technically feasible and may be cost-prohibitive to implement. As a result, the final rule is likely to limit the feasibility of operating existing coal units until CCS technology has been demonstrated to be technically and economically deployable, a timeframe for which does not currently exist.

On February 15, 2024, the New York Attorney General, Letitia James, led a coalition of 16 states in filing a motion to intervene with the Supreme Court against the EPA's final rule, arguing that the EPA lacks authority to establish these regulations. On April 18, 2024, the Florida Attorney General, Ashley Moody, joined and filed a lawsuit to block the new EPA emissions rule.

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.

Several utilities converted of oil-fired and coal-fired steam units to natural gas-fired combined cycle units, or converted or upgraded to run on natural gas for all or a majority of their fuel. This trend continues, with direct coal-fired steam to natural gas-fired steam, such as OUC's conversion of Stanton Unit 2 by 2027. Additional planned conversions from coal or other solid fuels are planned by the TYSP Utilities, including TECO's conversion of the Polk Unit 1 integrated gasification combined cycle unit, the only petcoke fueled combined cycle within the State, to a natural gas-fired combustion turbine.

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. Overall, 560 MW of additional summer firm capacity is from uprates to existing natural gas fired combined cycle units. In addition, DEF and OUC plan transmission upgrades that will allow them improved access to capacity from existing natural gas units at the Osprey and Osceola plant sites in 2025. While these do not change the amount of capacity available in the state as a whole, it improves the ability to deliver capacity where needed on the system.

Utilities are also investigating potential future conversions or dual-firing with hydrogen. For example, FPL's hydrogen pilot at its Okeechobee natural gas-fired combined cycle facility, approved as part of FPL's 2021 Settlement Agreement,[9] involves using a solar powered electrolyzer to produce hydrogen from water and replacing up to 5 percent of the fuel mix with hydrogen in the unit's combustion turbines.

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 2,456 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 four units totaling 1,167 MW of

[9] Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

capacity to be retired by 2029, followed by natural gas-fired steam generation, with four units totaling 750 MW of capacity to be retired by 2030.

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			
2024	FPL	Daniel 1&2	502
2025	FMPA-OUC	Stanton Unit 1	450
2029	FPL	Scherer Unit 3	215
		Coal Steam Subtotal	**1,167**
Oil Combustion Turbine Retirements			
2026	DEF	Bayboro Units P1-P4	151
2027	DEF	Debary Units P2-P6	227
2027	DEF	P L Bartow Units P1 & P3	82
2027	FPL	Lansing Smith Unit A	32
		Oil CT Subtotal	**492**
Natural Gas Steam Retirements			
2024	FPL	Gulf Clean Energy Center 4	75
2026	FPL	Gulf Clean Energy Center 5	75
2027	GRU	Deerhaven FS01	76
2030	JEA	Northside Unit 3	524
		Gas Steam Subtotal	**750**
Natural Gas Combustion Turbine Retirements			
2025	FPL	Pea Ridge 1-3	12
2031	GRU	Deerhaven GT1 & GT2	35
		Gas CT Subtotal	**47**
		Total Retirements	**2,456**

Source: 2024 Ten-Year Site Plans

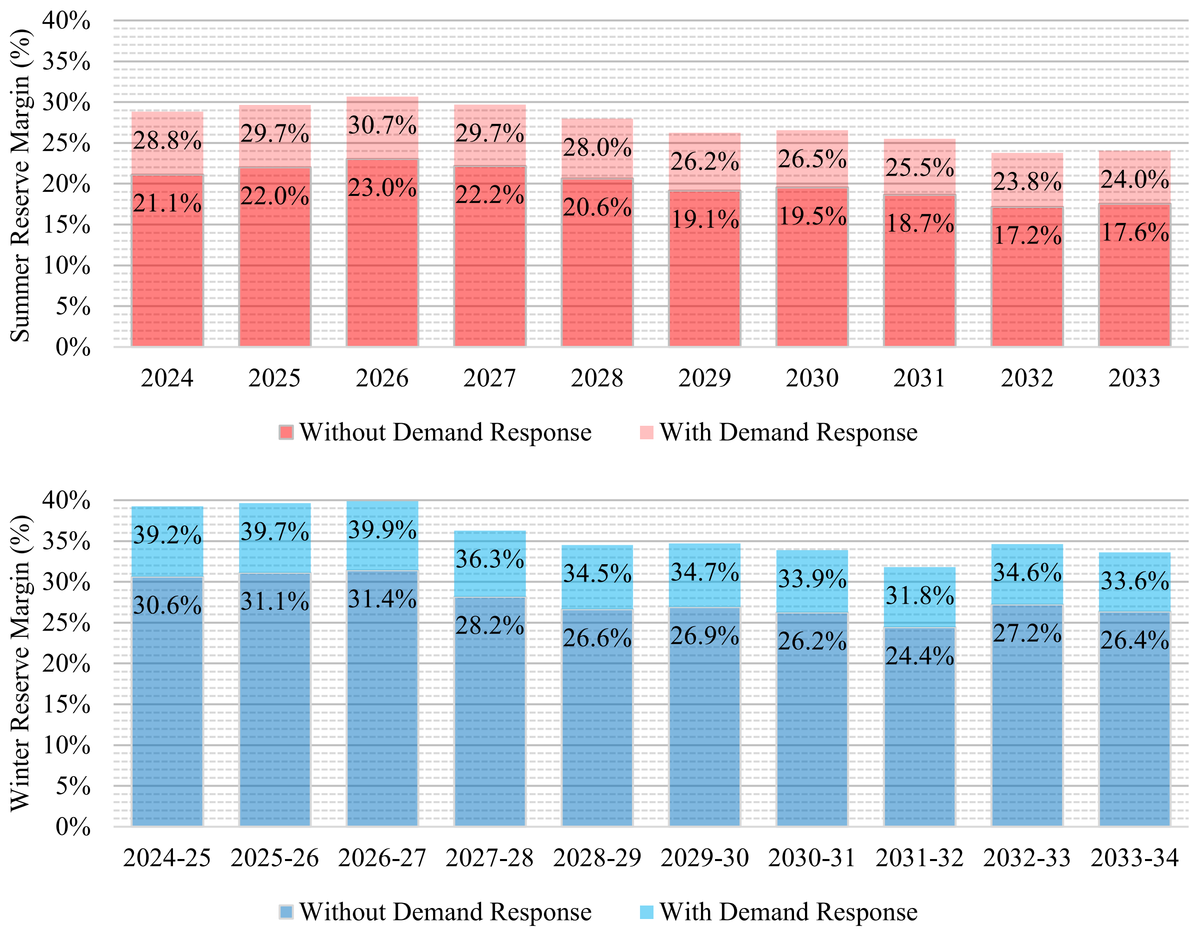
Reliability Requirements

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

Figure 15: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2024 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 15, 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 7.2 percent in summer and 7.9 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 reconsider the value of the discounted rates or credits. 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.

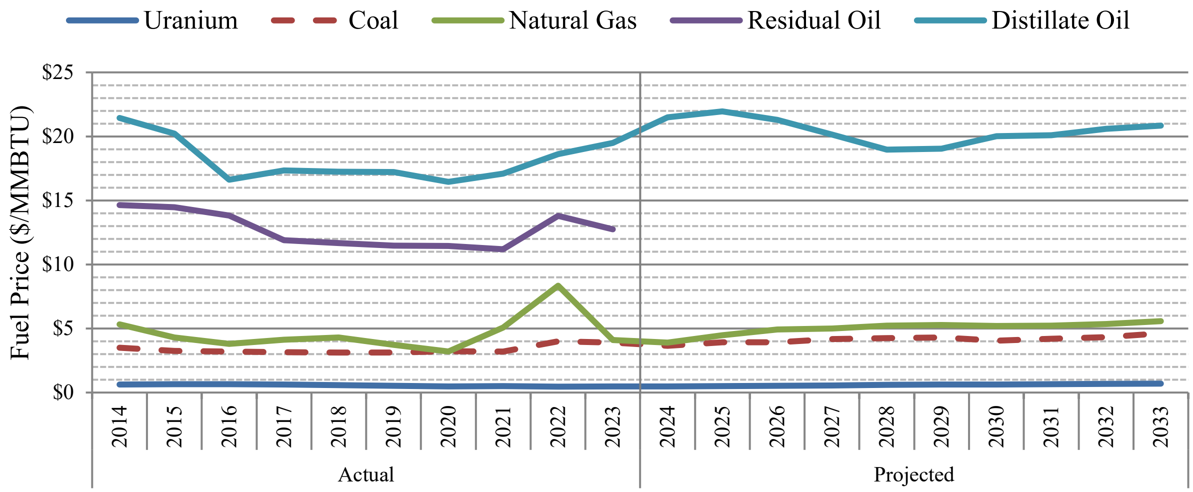
Fuel Price Forecast

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 16 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 72.7 percent of electric generation in 2023. As shown in Figure 16, the price of natural gas continued to decline from 2014 until 2020. However, the weighted average natural gas prices saw a sizable increase from 2020 through 2022, with a peak of $8.00 per million British Thermal Units (MMBTUs) in 2022, before returning to a price of approximately $4.00/MMBTU in 2023. The price of natural gas is forecast to stabilize in 2024, and then increase slightly through 2033. Meanwhile, the price of coal was stable from 2014 through 2022. Even so, forecasts anticipate coal prices to increase gradually from $3.64 in 2024 to $4.62 in 2033. It should be noted that the use of coal is projected to decrease substantially through 2033.

Distillate oil remains the most expensive fuel, which partially 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 2023. The truncated graph on Figure 16 reflects this phasing out of residual oil.

Figure 16: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities



Source: TYSP Utilities' Data Responses

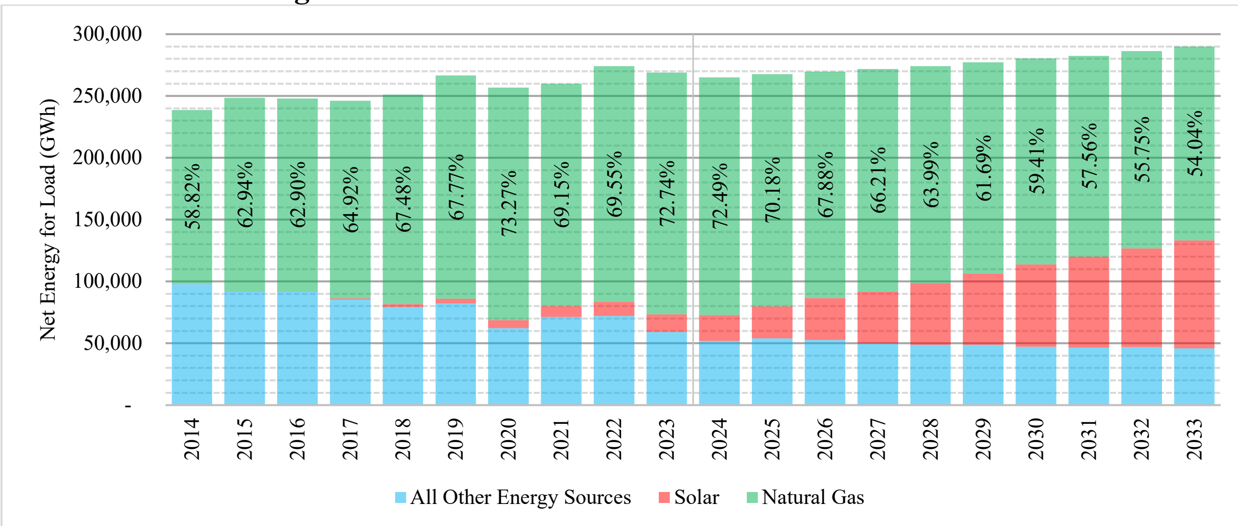
As shown in Figure 16, the price of natural gas continued to decline from 2014 until 2020. Even though current forecasts project the price of natural gas to remain relatively stable over the long term, there remains some degree of natural gas price volatility over the short and medium term. For instance, natural gas price volatility was reflected in the 2024 requests for fuel factor mid-course corrections (increases or decreases in customer fuel charges) filed by FPL, DEF, and TECO. FPL's mid-course correction was approved by the Commission on April 10, 2024, and DEF and TECO's were approved on May 24, 2024.[10]

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 17 illustrates, natural gas was the source of approximately 69.6 percent of electric energy consumed in Florida in 2023. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline throughout the remainder of the planning period, offset by solar generation. Solar generation is anticipated to exceed all non-natural gas energy sources combined by 2028.

[10] Docket No. 20240001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

Figure 17: State of Florida - Natural Gas Generation

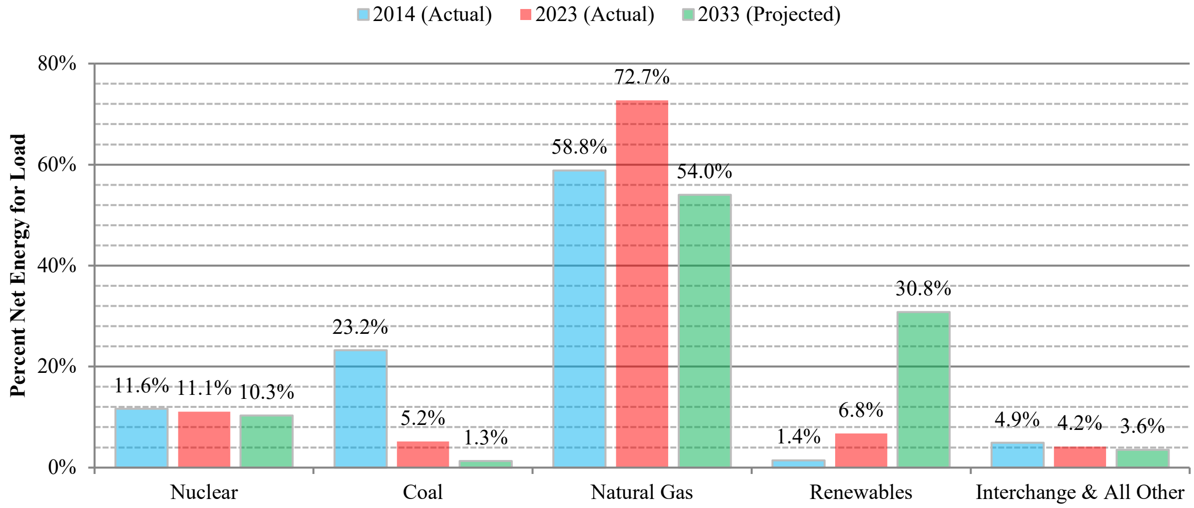


Source: FRCC 2015-2024 Regional Load and Resource Plans

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 18 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2014 and 2023, and forecast year 2033. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2028.

Figure 18: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2015-2024 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.[11] 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

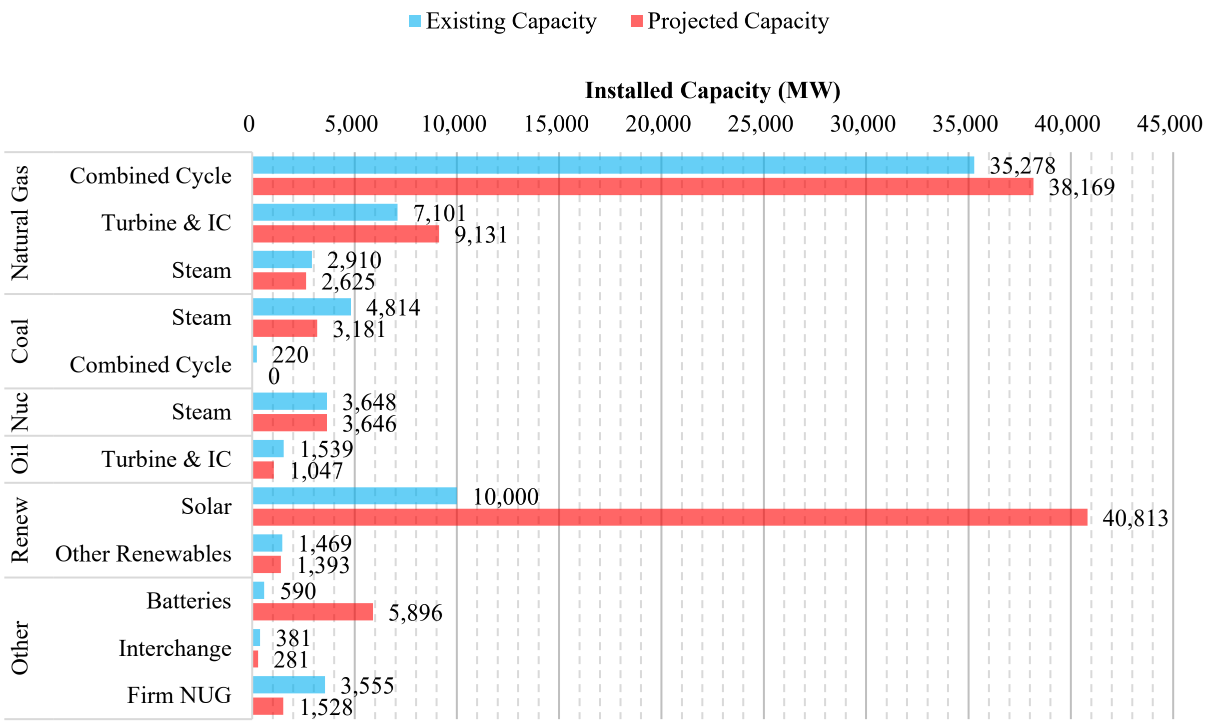
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, 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 supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

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

Figure 19 illustrates the present and future aggregate capacity mix. The capacity values in Figure 19 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2024 Ten-Year Site Plans and the FRCC's 2024 Regional Load and Resource Plan.

Figure 19: State of Florida - Current and Projected Installed Capacity



Source: FRCC 2024 Regional Load and Resource Plan and 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. There are two planned units, both natural gas-fired combined cycles, requiring certification under the PPSA; a 571 MW unit with an in-service date of 2032 for SEC, and a 518 MW unit with an in-service date of 2030 for JEA. While solar generation is covered under the Power Plant Siting Act, all future solar projects are below the 75 MW threshold, and therefore are not required to seek approval from the Commission prior to construction.

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 and 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 (also called reciprocating engines) units, taken together, represent the third most abundant type of generating capacity, behind installed solar generation as well. As combustion turbines and internal combustion units 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 3,287 MW of additional capacity from new natural gas-fired generating units proposed by the 2024 Ten-Year Site Plan utilities. In addition to the new generation listed below, FMPA is acquiring three existing merchant facilities, all natural gas-fired combined cycle units, for a total of 332 MW.

Table 11: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
PPSA Approved Units					
2026	SEC	Shady Hills Energy Center	CC	546	
			Subtotal	**546**	
New Units Requiring PPSA Approval					
2030	JEA	Advanced 1x1 CC	CC	576	
2032	SEC	Unnamed CC	CC	571	
			Subtotal	**1,147**	
New Units Not Requiring PPSA Approval					
2024	LAK	Mcintosh ME1-ME6	IC	120	6 Units
2025-2026	TECO	South Tampa Resiliency Project	IC	75	2 Phases – 4 Units Total
2029	SEC	Unnamed CT	CT	317	
2030	TECO	Future CT 1	CT	222	
2032	DEF	Undesignated CT 1 & 2	CT	430	2 Units
2033	DEF	Undesignated CT 3 & 4	CT	430	2 Units
			Subtotal	**1,594**	
			Total	**3,287**	

Source: 2024 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 2024 Ten-Year Site Plans and the FRCC 2024 Regional Load and Resource Plan that require TLSA certification. The only planned line has already received the approval of the Commission.

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	Sweatt to Whidden	79	230	05/2022	09/2022	06/2026

Source: 2024 Ten-Year Site Plans and FRCC 2024 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. FPL's parent company, NextEra Energy Inc., acquired Gulf Power Company (GPC) in January 2019. Resource planning is now being done for the single entity of FPL, with the former GPC territory referred to as FPL's Northwest Florida Division (FPL NWFL). 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, FPL's service area had approximately 5,845,160 customers and annual retail energy sales of 127,904 GWh, or approximately 54.7 percent of Florida's annual retail energy sales. The total number of customers grew by approximately 1.2 percent in 2023 which is in line with FPL's normal growth rates.

Over the past 10 years, FPL's customer base has increased by 13.5 percent, while retail energy sales have grown by approximately 10.8 percent. For the 2024 TYSP forecast horizon, customers for the FPL system are forecasted to grow by 1.2 to 1.3 percent per year. According to FPL, its total customer growth is being driven primarily by growth in residential customer numbers.

FPL's weather-normalized energy consumption per customer for residential and commercial customers reflect the impacts of the pandemic and the resulting return to more normal conditions. In 2023, residential usage decreased by 0.1 percent as, according to the Company, a strong economy led to customers spending less time at home (i.e. returning to work-place/school). Commercial usage, on the other hand, increased by 0.4 percent due to rebounding commercial activity. FPL's industrial use per customer declined by 11.6 percent, but this decline was attributable to strong growth in the number of small industrial customers with low average usage.

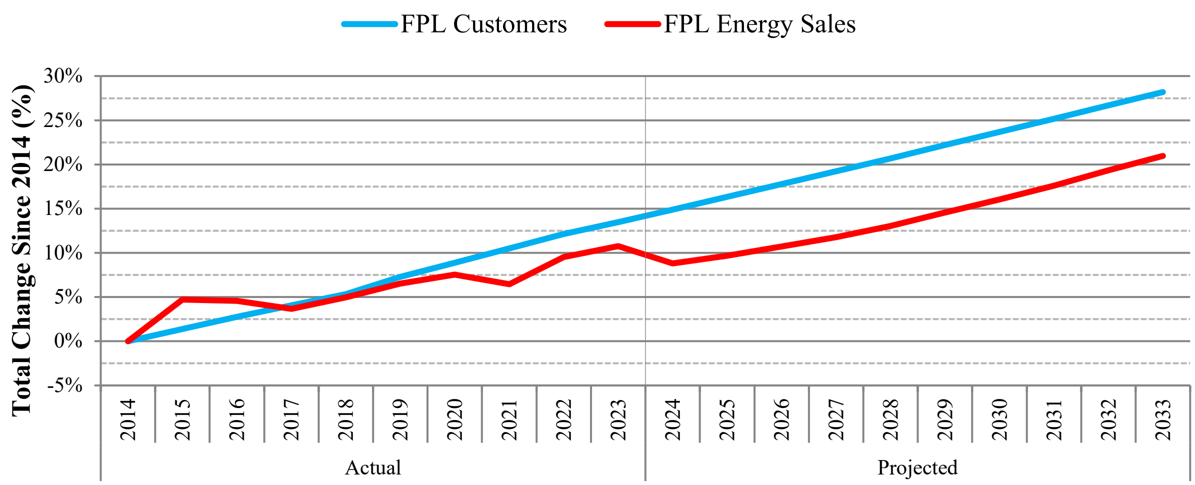
Over the current TYSP forecast horizon, residential use per customer is forecasted to be flat or slightly grow up to 0.6 percent due to continued economic growth as well as increased adoptions of electric vehicles. Commercial usage is forecast to decline between 0.1 to 0.7 percent per year over the forecast horizon due to continued improvements to equipment efficiencies.

FPL's weather-normalized annual retail energy sales increased by 0.8 percent in 2023, driven by growth in the residential class. Residential energy sales increased by 1.1 percent due to continued customer growth. Commercial energy sales increased due to both customer and usage growth. Industrial energy sales decreased but had a negligible impact on total retail energy sales because the industrial class sales are a small proportion of total retail energy sales.

For the 2024 TYSP forecast horizon, FPL's total retail energy sales are forecasted to grow by 0.8 to 1.3 percent per year. This projected retail energy 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 of customers.

Figure 20 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan FPL filed in its 2024 TYSP.

Figure 20: FPL Growth

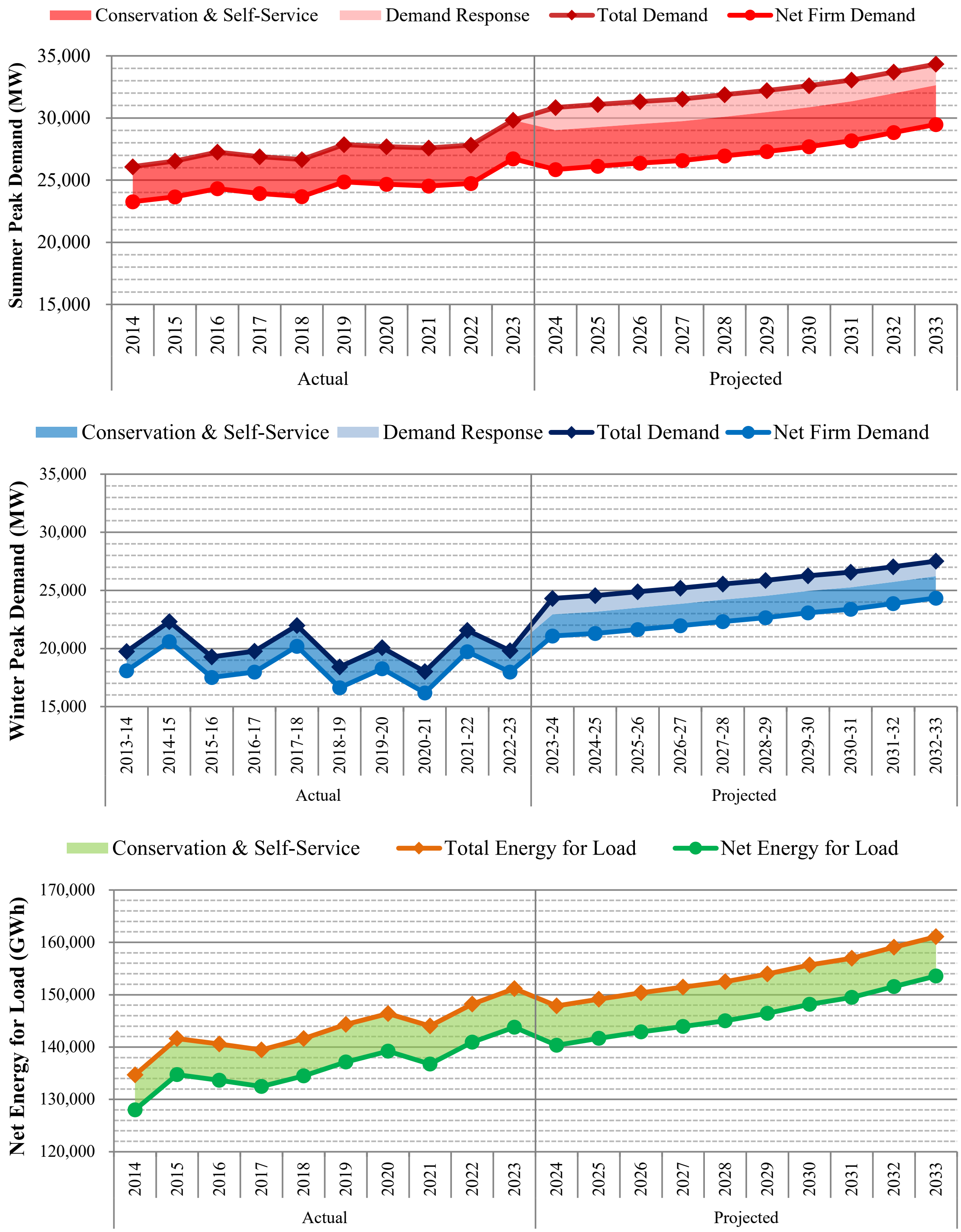


Source: 2024 Ten-Year Site Plan

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. The three graphs in Figure 21 show FPL and GPC's combined seasonal peak demand, summer and winter, and net energy for load, for the historic years 2014 through 2021, with the integrated FPL/GPC historical data for 2022 and 2023, and forecast for years 2024 through 2033.

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 Commission is currently reviewing FPL's 2025-2034 DSM goals. These goals are scheduled to be voted on at the December 3, 2024 Commission Conference and, in 2025, the Commission will review FPL's plan designed to achieve those goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, FPL assumes the trends in these goals will be extended through the forecast period (through 2033), as reflected in Figure 21. 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. During the past 10 years, demand response has not been activated during seasonal peak demand.

Figure 21: FPL Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 13 shows FPL's actual net energy for load by fuel type for 2023 and the projected fuel mix for 2033. FPL relies primarily upon natural gas for energy generation, making up 75 percent of net energy for load in 2023. FPL is projected to use natural gas for less than half of its energy generation by 2033. Only two utilities, FPL and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2033, natural gas will still be the highest individual fuel at 42 percent, while renewables will account for 39 percent, followed by nuclear at 19 percent.

Table 13: FPL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	105,854	**75.4%**	64,551	**42.0%**
Coal	472	**0.3%**	0	**0.0%**
Nuclear	28,767	**20.5%**	28,830	**18.8%**
Oil	233	**0.2%**	2	**0.0%**
Renewable	10,217	**7.3%**	59,440	**38.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(5,079)	**-3.6%**	857	**0.6%**
Total	**140,464**		**153,681**	

Source: 2024 Ten-Year Site Plan

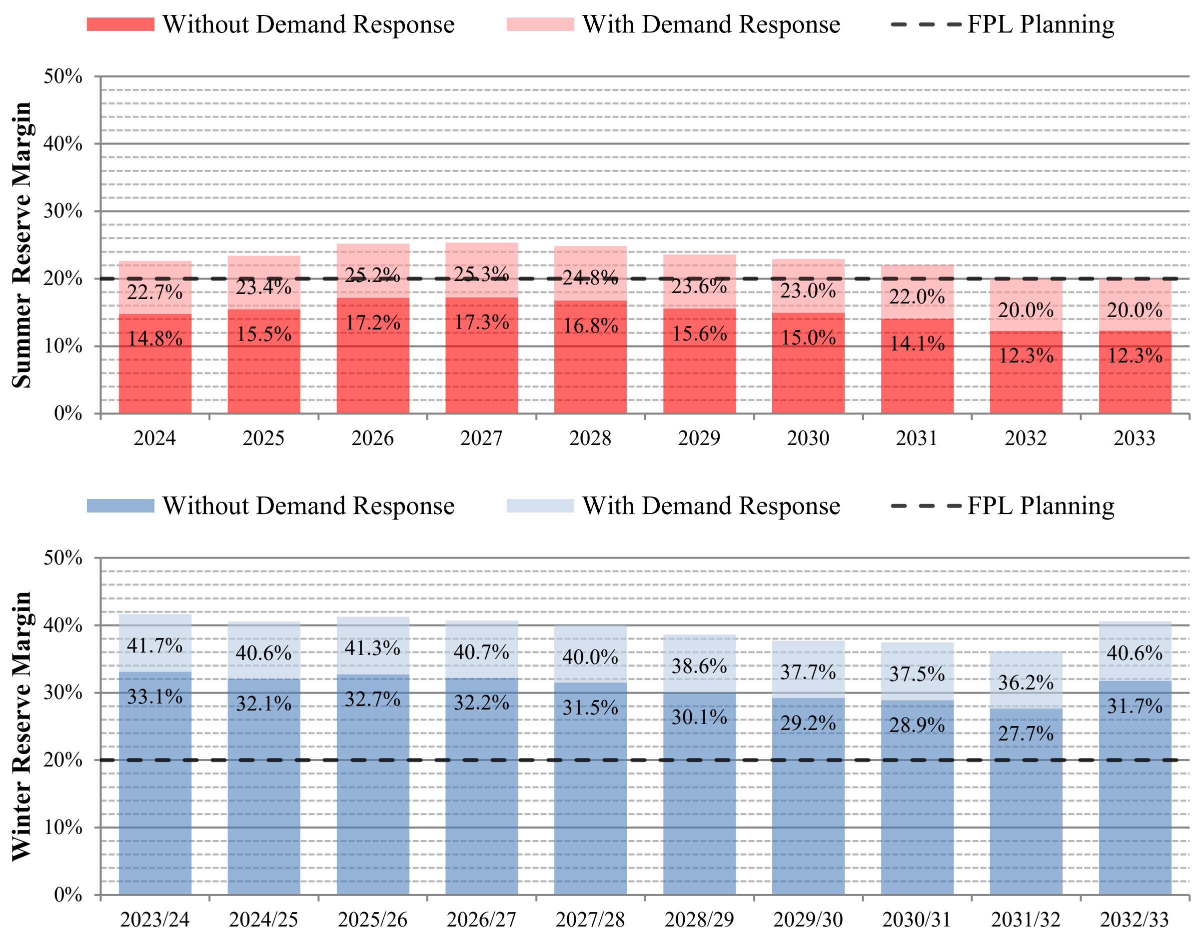
Reliability Requirements

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.[12] Figure 22 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.

[12] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 22: FPL Reserve Margin Forecast



Source: 2024 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 Company 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 as are described in Table 14. Particularly noteworthy is the Company's plan to retire its three remaining coal units, totaling 717 MW, which consist of FPL's partial ownership of Scherer Unit 3 and Daniel Units 1 and 2, all assets which it acquired from its purchase of GPC. FPL also plans the retirement of another 197 MW of assets, primarily natural gas-fired steam plants. These retirements are partially offset by planned upgrades to its existing natural gas combined cycle generating units over the planning period, which increase summer capacity by 123 MW.

FPL does not plan any new fossil generating unit additions over the next 10-year period, only solar and battery facilities. The majority of changes on FPL's system are from new solar photovoltaic plants, with a planned 282 sites totaling 21,009 MW in capacity, of which 2,742 MW are considered firm for the summer peak. In addition, FPL anticipates adding a total of 4,022 MW of battery storage, of which 2,159 MW will be considered firm for purposes of summer peak. None of these additions require a need determination pursuant to the PPSA.

Table 14: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2024	Daniel 1 & 2	BIT ST	502		2 Units Total
2024	Gulf Clean Energy Center 4	NG ST	75		
2025	Pea Ridge 1-3	NG GT	12		3 Units Total
2026	Gulf Clean Energy Center 5	NG ST	75		
2027	Lansing Smith 3A	DFO GT	32		
2028	Scherer 3	BIT ST	215		
2029	Perdido 1 & 2	LFG IC	3		2 Units Total
		Total Retirements	**914**	**-**	
New Units					
2024	Sited Solar Plants	SUN PV	2,235	982	30 Sites
2025	Sited Solar Plants	SUN PV	894	351	12 Sites
2025	Unsited Energy Storage	BAT	522	349	
2026	Sited Solar Plants	SUN PV	2,235	429	30 Sites
2027	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2027	Unsited Energy Storage	BAT	300	219	
2028	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2028	Unsited Energy Storage	BAT	300	213	
2029	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2029	Unsited Energy Storage	BAT	300	201	
2030	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2030	Unsited Energy Storage	BAT	300	191	
2031	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2031	Unsited Energy Storage	BAT	300	186	
2032	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2032	Unsited Energy Storage	BAT	300	150	
2033	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2033	Unsited Energy Storage	BAT	1,700	650	
		Total New Units	**25,031**	**4,901**	
		Net Additions	**24,117**		

Source: 2024 Ten-Year Site Plan

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Company's service territory is within the FRCC region and is primarily located 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, DEF had approximately 1,968,221 customers and annual retail energy sales of 40,832 GWh, or approximately 17.4 percent of Florida's annual retail energy sales. DEF's total customers and total retail energy sales respectively grew approximately 1.8 percent and 0.8 percent in 2023. Over the last 10 years, DEF's customer base has increased by 15.8 percent, while retail energy sales have grown by 9.6 percent.

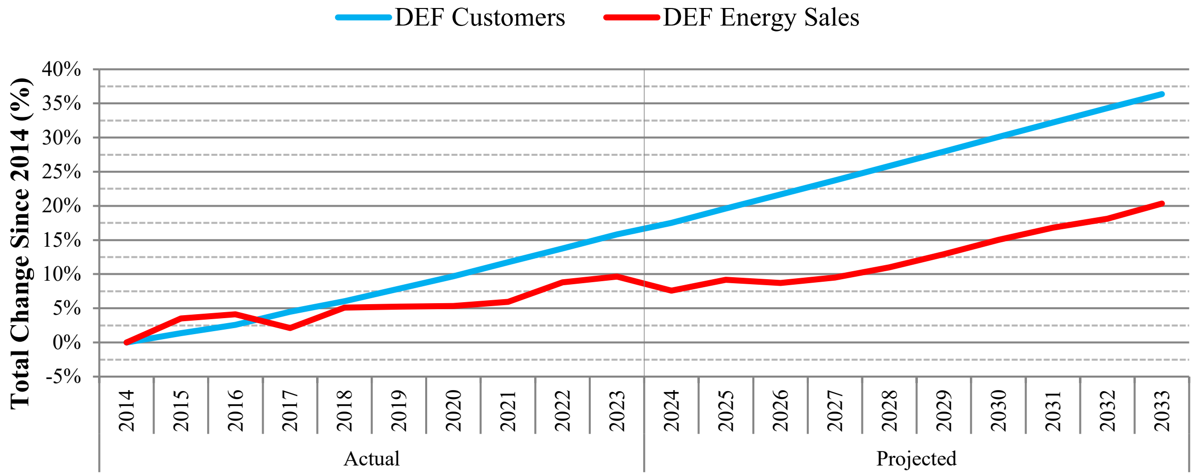
DEF's customer growth has always been dominated by the residential and commercial customer classes. Customer growth trends are driven by broad economic and demographic factors such as population growth, migration, retirement, affordable housing, mortgage rates and job growth. More recent information 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 Company's forecasted number of customers and forecasted energy consumption per customer. Fluctuations of per customer usage for DEF's residential and commercial classes are primarily driven by variations 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 energy consumption per customer, the Company is aware that the ability to self-generate recently has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generation, reducing energy consumption from the power grid. Similarly but more significantly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind their meters. The Company also noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal.

For the 2024 TYSP forecast horizon, DEF's forecast results indicate that the Company's customer base is projected to grow at an average annual rate of 1.7 percent approximately, and its retail energy sales are projected to grow at an average annual rate of 1.3 percent approximately.

Figure 23 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan DEF filed in its 2024 TYSP.

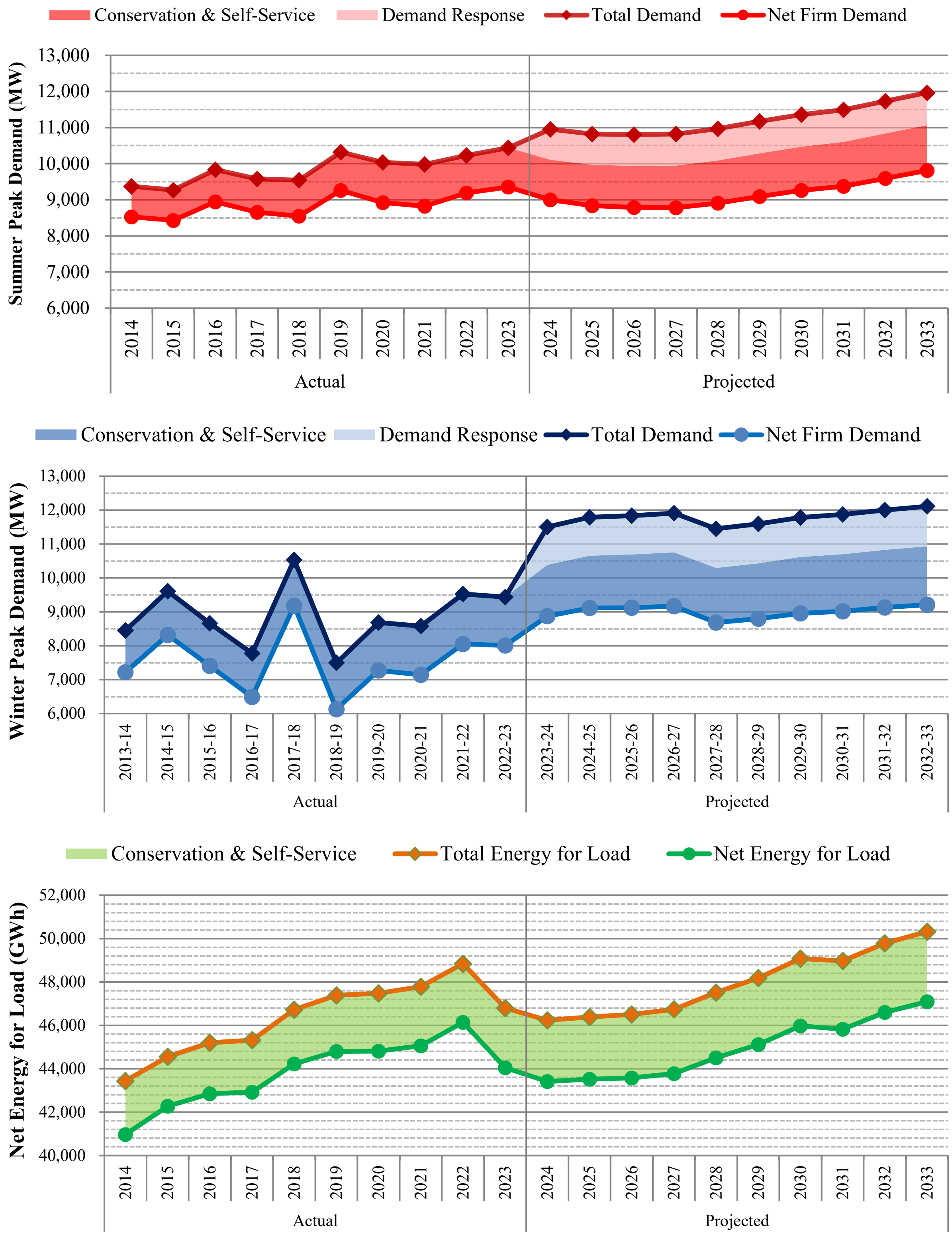
Figure 23: DEF Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 24 show DEF's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. 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 August 2024, the Commission established demand side management goals for DEF for the years 2025 through 2034. In 2025, the Commission will review DEF's plan designed to achieve the Company's DSM goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, DEF assumes trends in these goals will be extended through the forecast horizon (through 2033).

Figure 24: DEF Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 15 shows DEF's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. DEF relies primarily upon natural gas for energy generation, making up approximately 81 percent of net energy for load in 2023. DEF plans to increase renewable energy generation over the planning period, somewhat offsetting natural gas and coal usage. DEF projects that renewable energy will provide 29 percent of its generation by 2033, which is the fourth highest percentage of renewable energy generation in 2033 of the TYSP Utilities. Natural gas would remain the primary fuel, at 68 percent in 2033.

Table 15: DEF Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	35,526	**80.7%**	31,801	**67.5%**
Coal	3,829	**8.7%**	1,873	**4.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	29	**0.1%**	10	**0.0%**
Renewable	2,788	**6.3%**	13,408	**28.5%**
Interchange	60	**0.1%**	2	**0.0%**
NUG & Other	1,814	**4.1%**	0	**0.0%**
Total	**44,046**		**47,094**	

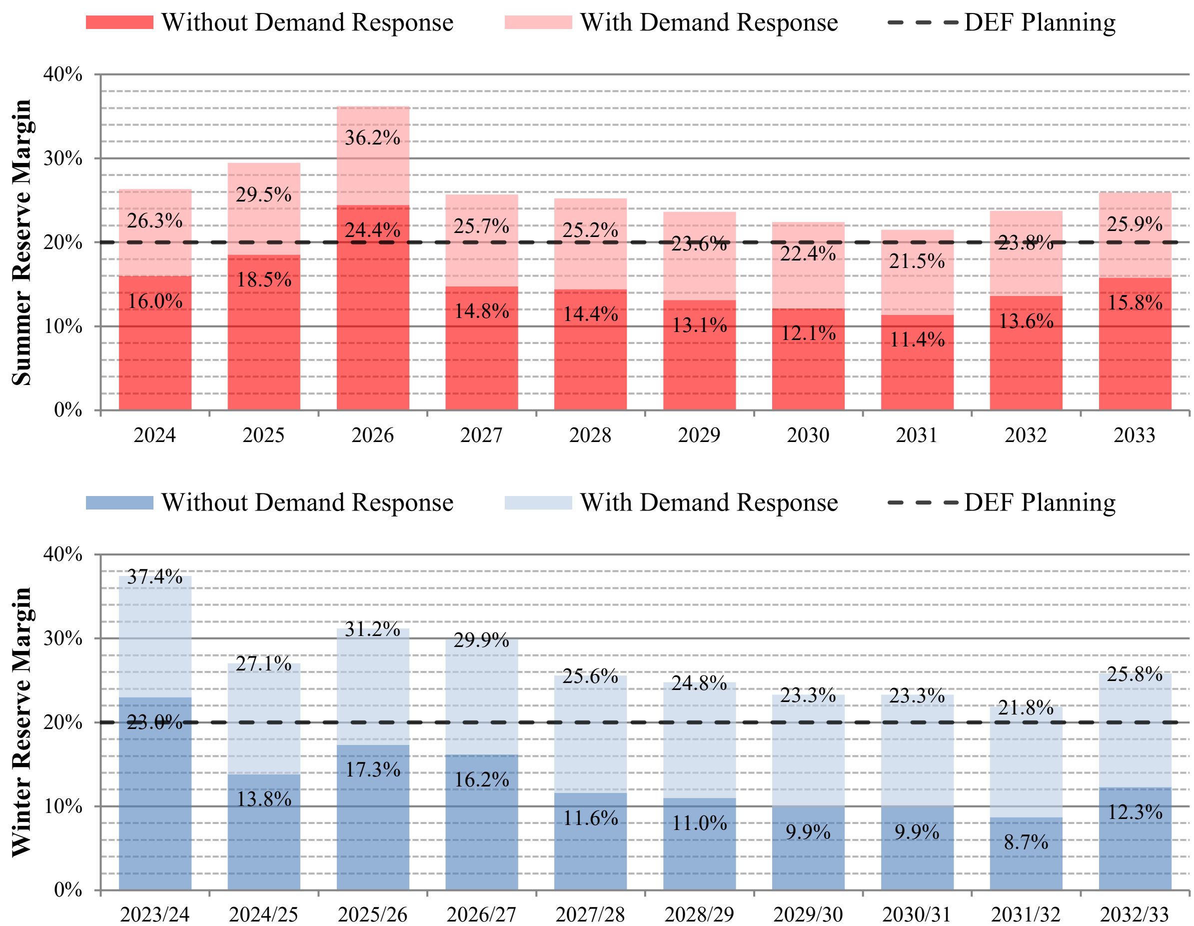
Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[13] 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.

[13] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 25: DEF Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 16. DEF plans to retire 460 MW of oil-fired combustion turbines by 2027 across three sites. These retirements are completely offset by modifications to its existing natural gas-fired combined cycle facilities. Uprates to the combustion turbines will increase their summer peak capacity by 389 MW, and improved transmission facilities will allow DEF to fully utilize the acquired Osprey plant, which increases its firm contribution to 347 MW.

DEF plans additions of fossil, renewable, and storage technologies over the planning period. For new fossil generation, DEF plans a total of four new natural gas-fired combustion turbines, with a pair of 215 MW units installed in 2032 and 2033, each. For renewables, DEF plans on 63 solar sites totaling 4,718 MW in capacity, of which 891 MW are considered firm for the summer peak. In addition, DEF plans on constructing 100 MW of independent battery storage, of which 90 MW are considered firm for summer peak. DEF also plans on collocating an additional 240 MW of battery storage at 6 of the solar sites, with 40 MW per site. DEF has designated these sites as Solar Plus Storage, and included the firm contribution of the battery as part of the solar facility. None of the solar and battery additions require a need determination pursuant to the PPSA.

Table 16: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2026	Bayboro P1 - P4	DFO CT	151		4 Units
2027	Debary P2 - P6	DFO CT	227		5 Units
2027	Bartow P1, P3	DFO CT	82		2 Units
		Total Retirements	**460**	**0**	
New Units					
2024	Sited Solar Plants	PV SUN	300	171	4 Sites
2025	Sited Solar Plants	PV SUN	300	75	4 Sites
2026	Unsited Solar Plants	PV SUN	374	94	5 Sites
2027	Unsited Solar Plants	PV SUN	374	94	5 Sites
2027	Unsited Energy Storage	BAT	100	90	
2028	Unsited Solar Plant	PV SUN	300	30	4 Sites
2028	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2029	Unsited Solar Plant	PV SUN	374	37	5 Sites
2029	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2030	Unsited Solar Plant	PV SUN	449	45	6 Sites
2030	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2031	Unsited Solar Plant	PV SUN	599	60	8 Sites
2032	Unsited Solar Plant	PV SUN	599	60	8 Sites
2032	Undesignated CTs 1 & 2	NG CT	430		2 Units
2033	Unsited Solar Plant	PV SUN	599	60	8 Sites
2033	Undesignated CTs 3 & 4	NG CT	430		2 Units
		Total New Units	**5,678**	**981**	
		Net Additions	**5,218**		

Source: 2024 Ten-Year Site Plan

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Company'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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

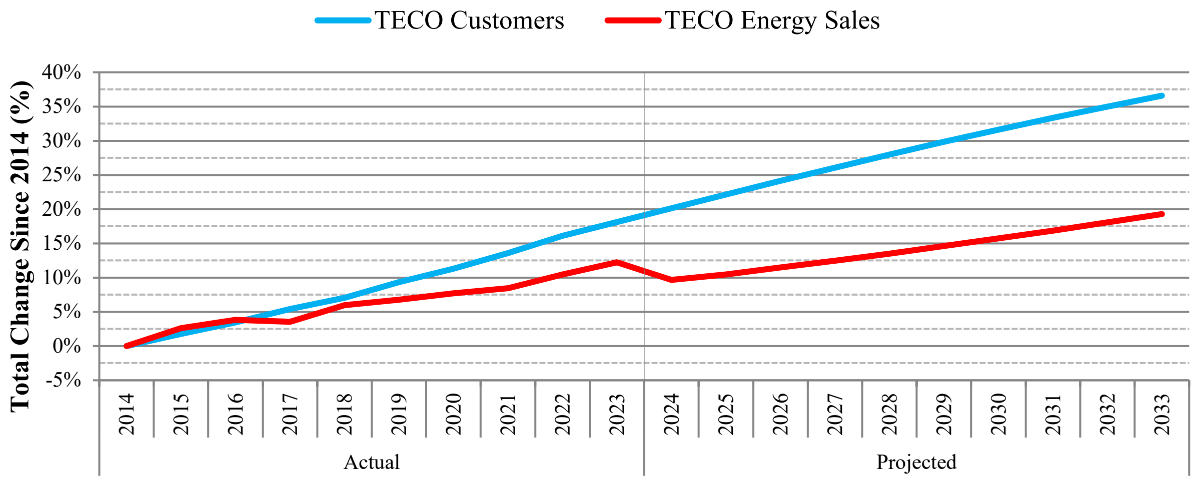
In 2023, TECO had approximately 834,144 customers and annual retail energy sales of 20,791 GWh or approximately 8.9 percent of Florida's annual retail energy sales. Over the last 10 years, TECO's customer base has increased by approximately 18.1 percent, while retail energy sales have increased by approximately 12.2 percent.

TECO's total customer growth in 2023 averaged 1.8 percent approximately 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 1.5 percent annually. The primary driver of customer growth in the residential sector will be new construction and increasing net in-migration to the Company's service area.

TECO's average annual energy consumption per residential customer is slightly higher in 2023 than in 2022, primarily due to the record-breaking heat in 2023. Likewise, the Company's commercial per customer usage was slightly higher in 2023 than in 2022 due to the record-breaking heat. TECO's industrial per customer usage in 2023 was also higher than in 2022. The primary driver of this increase, in addition to hotter weather, was the industrial phosphate sector had less self-serving generation and more energy purchases from TECO. Over the next 10 years, TECO expects average energy consumption per residential customer to decline at an average annual rate of 0.2 percent. The main drivers behind the decline are the increases in the energy efficiencies of the appliances, lighting, and new homes, as well as the conservation efforts and changes in housing mix. The Company also expects average energy consumption per commercial and industrial customer to decline 0.2 and 0.1 percent, respectively.

For the next 10 years, TECO's retail energy sales are projected to grow at an annual average rate of approximately 0.9 percent. This is below the projected customer growth rate of 1.4 percent primarily due to continued per customer energy consumption declines, as well as declines in the phosphate sector as the mining industry continues to move south and out of the Company's service territory. Figure 26 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan TECO filed in its 2024 TYSP.

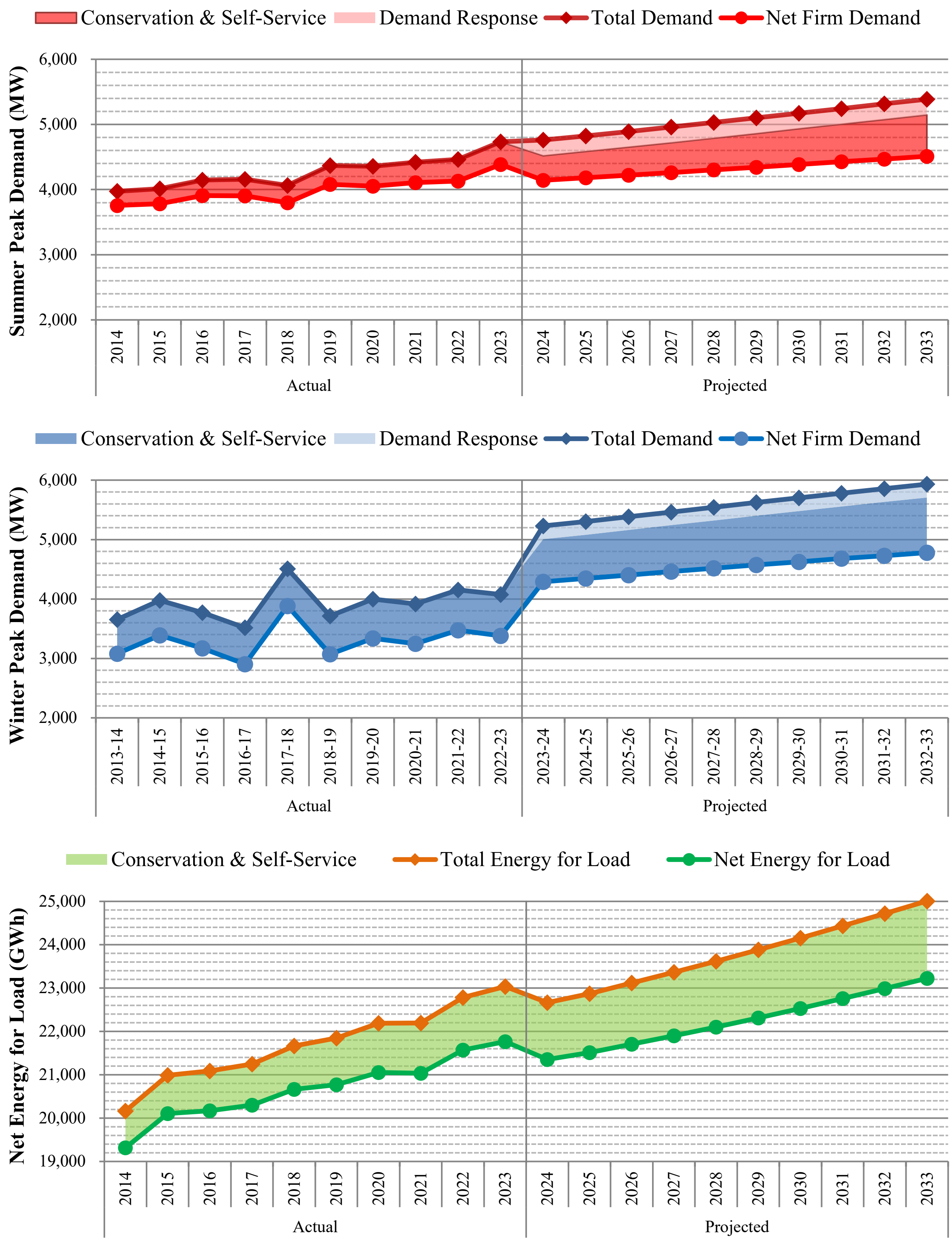
Figure 26: TECO Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 27 show TECO's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. 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 August 2024, the Commission established demand side management goals for TECO for the years 2025 through 2034. In 2025, the Commission will review TECO's plan designed to achieve the Company's DSM goals. In preparing its 2024 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 2033).

Figure 27: TECO Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 shows TECO's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. Based on its 2024 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 82 percent of net energy for load in 2023 and is projected to account for approximately 72 percent in 2033. 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 8 percent to 27 percent by 2033.

Table 17: TECO Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	17,814	**81.8%**	16,721	**72.0%**
Coal	769	**3.5%**	139	**0.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	1,748	**8.0%**	6,191	**26.7%**
Interchange	21	**0.1%**	150	**0.6%**
Other	1,412	**6.5%**	23	**0.1%**
Total	**21,767**		**23,224**	

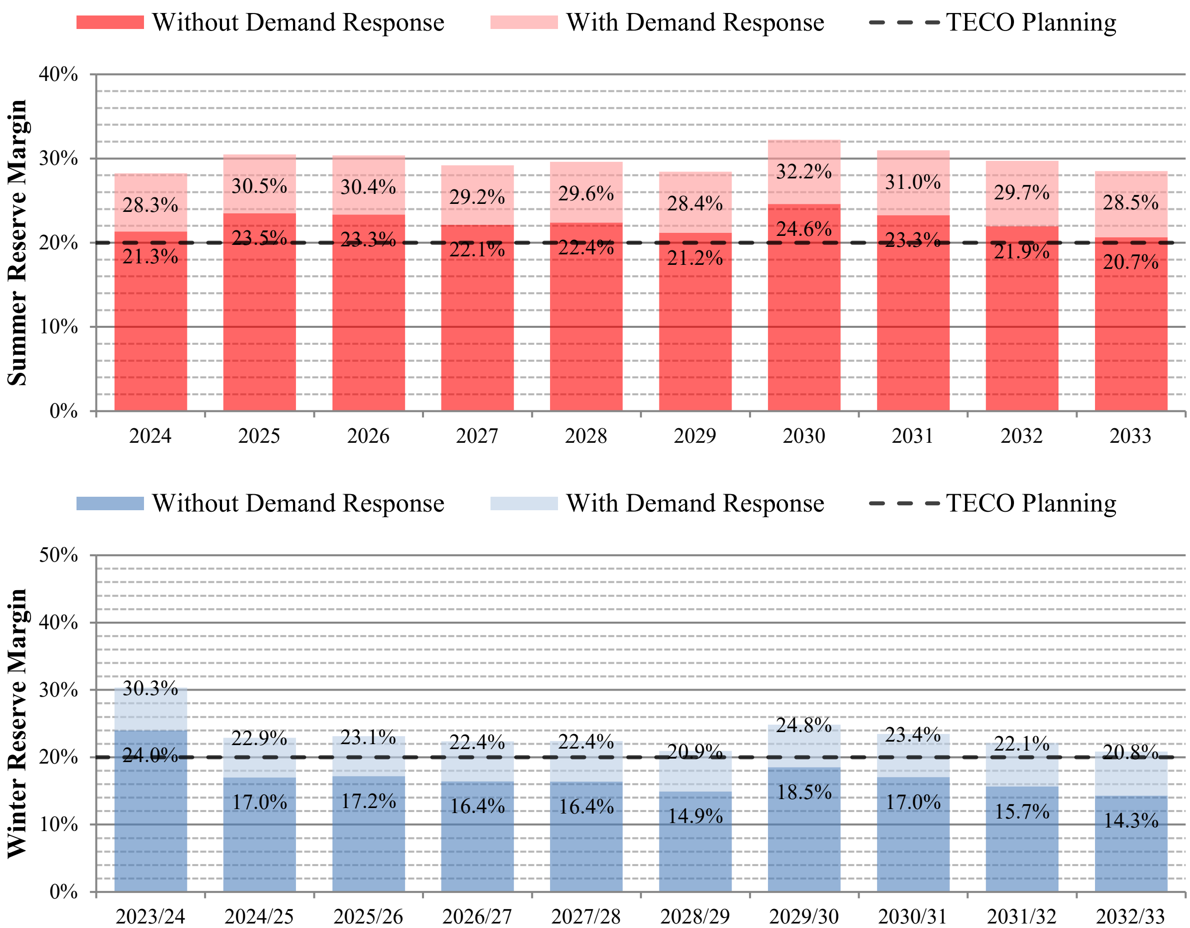
Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[14] TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 28 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs 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.

[14] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 28: TECO Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

For its existing generating units, TECO plans uprates at its existing Bayside combined cycle facilities for an additional 72 MW of capacity, offset by the conversion of the petcoke fueled Polk 1 integrated gasification combined cycle to a natural gas-fired simple cycle system, which reduces its net firm capacity by 30 MW.

TECO plans additions of fossil, renewable, and storage technologies over the planning period, as described in Table 18. For natural gas-fired capacity, TECO plans on four 18.5 MW internal combustion units in 2025, and a single 222 MW combustion turbine in 2030. TECO plans on adding 23 solar sites for 1,585 MW of solar capacity, of which only 35 MW will be considered firm for purposes of summer peak. The Company will also be installing five battery sites with a total of 185 MW of capacity, all of which is considered to contribute to the system peak.

Table 18: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
	None				
Total Retirements			**0**	**0**	
New Units					
2024	Sited Solar Plants	PV SUN	97	5	2 Units
2024	Sited Energy Storage	BAT	15		1 Unit
2025	South Tampa Resilience Project	NG IC	75		4 Units
2025	Sited Solar Plants	PV SUN	149	7	2 Sites
2025	Sited Energy Storage	BAT	100		3 Sites
2026	Sited Solar Plants	PV SUN	242	8	4 Sites
2027	Sited Solar Plant	PV SUN	74	1	1 Site
2027	Unsited Solar Plant	PV SUN	74	1	1 Site
2028	Sited Solar Plants	PV SUN	130	2	2 Sites
2028	Unsited Solar Plant	PV SUN	74	1	1 Site
2028	Unsited Energy Storage	BAT	70	-	1 Site
2029	Unsited Solar Plant	PV SUN	149	2	2 Sites
2030	Unsited CT 1	NG CT	222	-	
2030	Unsited Solar Plant	PV SUN	149	2	2 Sites
2031	Unsited Solar Plant	PV SUN	149	2	2 Sites
2032	Unsited Solar Plant	PV SUN	149	2	2 Sites
2033	Unsited Solar Plant	PV SUN	149	2	2 Sites
Total New Units			**2,067**	**35**	
Net Additions			**2,067**	**35**	

Source: 2024 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 seventh largest electric utility and third largest municipal electric utility. While FMPA has 33 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the Company'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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

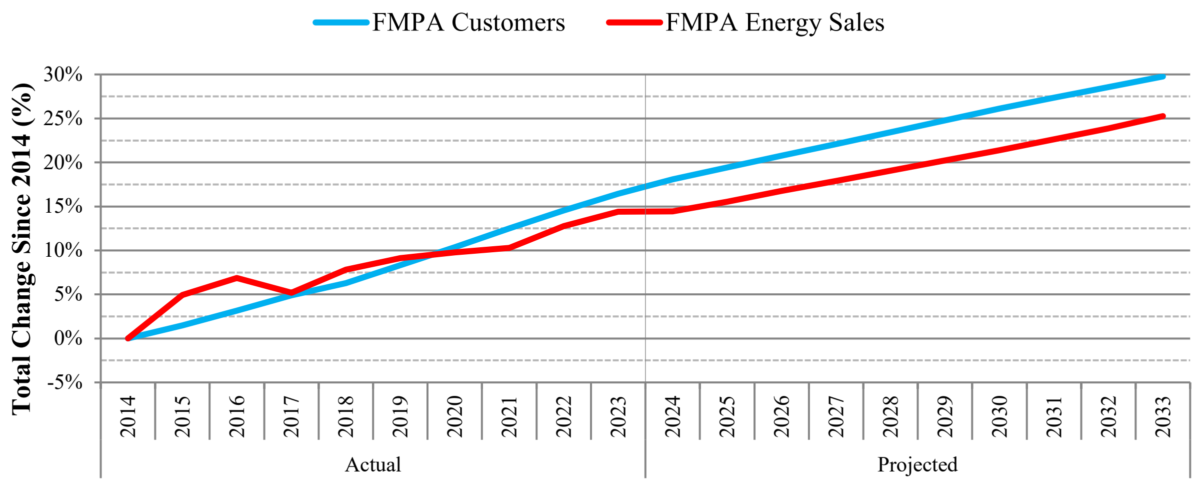
In 2023, FMPA had approximately 286,046 customers and annual retail energy sales of 6,124 GWh or approximately 2.6 percent of Florida's annual retail energy sales. Over the last 10 years, FMPA's customer base has increased by 16.4 percent, while energy sales have increased by 14.4 percent.

FMPA noted that, in aggregate, its energy usage has been relatively flat in both the residential and non-residential sectors after controlling for weather variation from normal conditions. There are countervailing factors that influence usage. In general, declines in electricity prices and population growth led to a small upward impact on usage. Concurrently, a continued orientation to conservation and continued improvement in energy efficiency place downward pressure on average usage. Both the continued conservation focus and energy efficiency improvements are driven primarily from technological advances, equipment standards, and enhanced building codes. These impacts have been offset by strong customer count gains in certain areas of the ARP Participant service territories

FMPA acknowledged that over the last several years, EVs have been adopted in increasing numbers in the Company's service area. Given the significance of this trend, the Company's 2024 load forecast includes a projection of the future impact of EV charging energy.

For the current 10-year forecast horizon, FMPA is projecting approximately a 1.1 percent average annual growth rate for its customer base, and a 1.0 percent average annual growth rate for energy sales. Figure 29 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan FMPA filed in its 2024 TYSP.

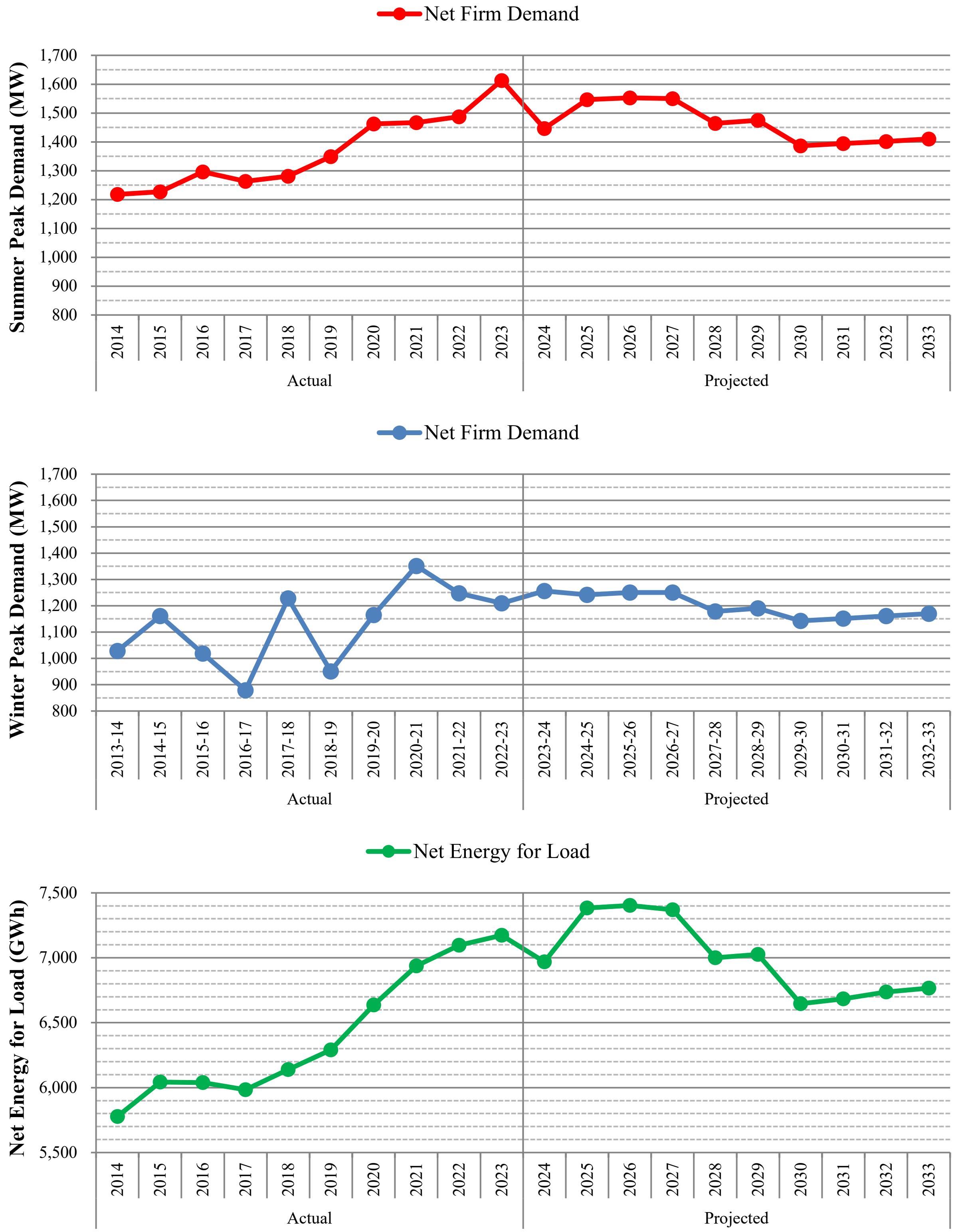
Figure 29: FMPA Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 30 show FMPA's seasonal peak demand and net energy for load for the historic years 2014 through 2023 and forecast years 2024 through 2033. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

Figure 30: FMPA Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows FMPA's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects to end energy generation from coal, but approximately 90 percent of energy would still be sourced from natural gas and nuclear. FMPA projects serving 10 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

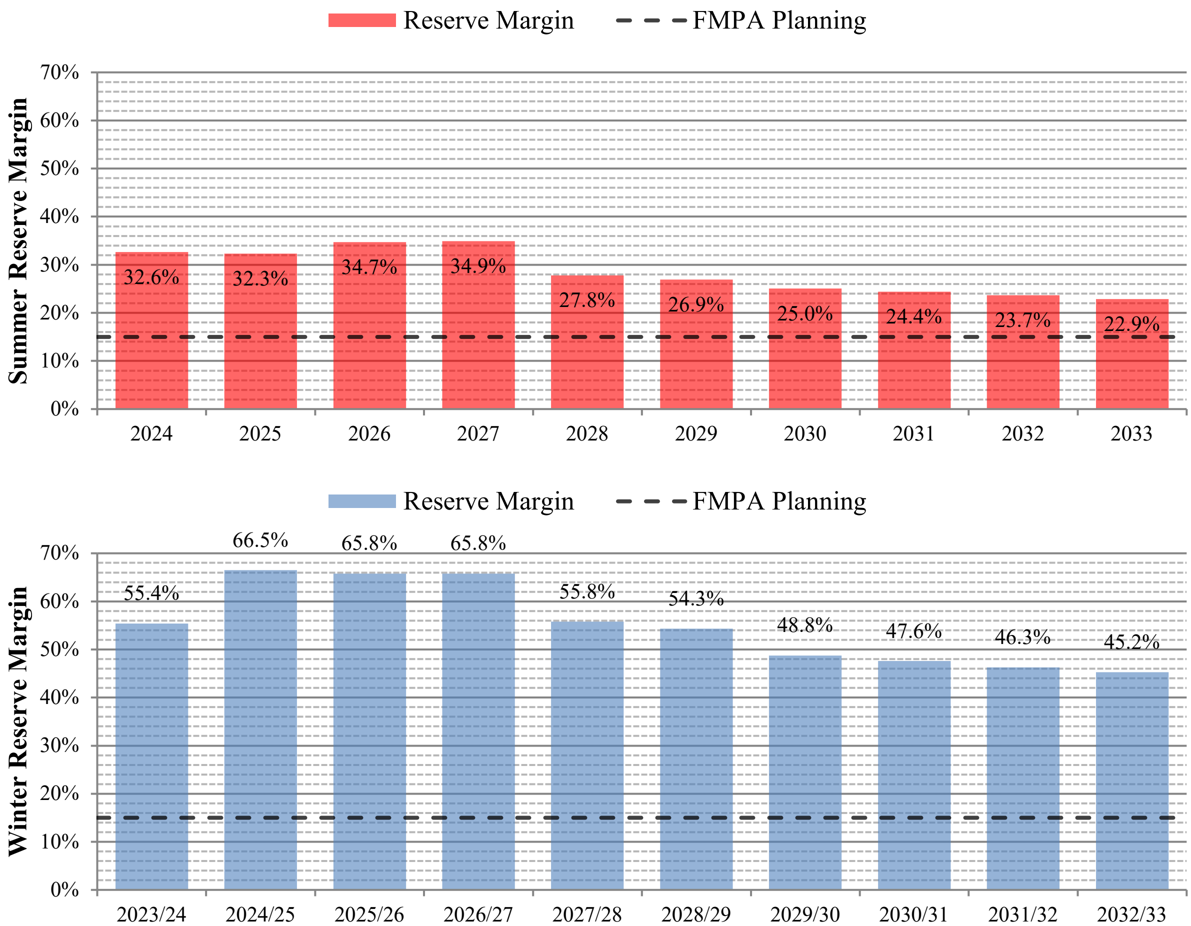
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	5,853	**81.6%**	5,743	**84.9%**
Coal	769	**10.7%**	0	**0.0%**
Nuclear	406	**5.7%**	376	**5.6%**
Oil	3	**0.0%**	1	**0.0%**
Renewable	143	**2.0%**	647	**9.6%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,174**		**6,766**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 31: FMPA Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

FMPA plans on retiring one unit and adding three new units during the planning period, as described in Table 20. FMPA plans on retiring the Stanton Energy Center Unit 1, a coal steam unit, in 2025. The three additions are all acquisitions of existing merchant natural gas-fired combined cycle facilities, two completed in 2024 and one projected for 2026. In addition, FMPA has entered into multiple purchased power agreements (PPAs) that will add a total of 193 MW of solar capacity by the end of 2026.

Table 20: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	Coal ST	119	Jointly Owned Unit
		Total Retirements	**119**	
New Units				
2024	Sand Lake Energy Center	NG CC	120	Merchant Acquisition
2024	Mulberry	NG CC	108	Merchant Acquisition
2026	Orange Cogeneration	NG CC	104	Merchant Acquisition
		Total New Units	**332**	
		Net Additions	**213**	

Source: 2024 Ten-Year Site Plan

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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

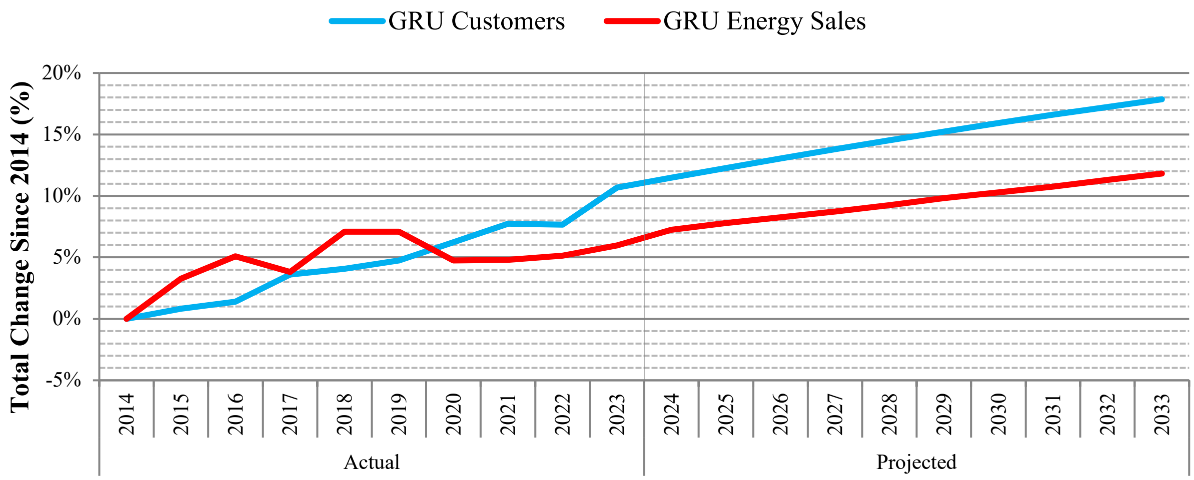
In 2023, GRU had approximately 103,865 customers and annual retail energy sales of 1,811 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Over the last 10 years, GRU's customer base has increased by approximately 10.7 percent, while retail energy sales have increased by approximately 6.0 percent.

GRU acknowledged that over the past 10 years, its residential energy consumption per customer declined approximately 0.2 percent per year, while its non-residential consumption per customer declined approximately 0.5 percent per year. For the next 10 years, the Utility projects that its residential energy usage per customer will stay relatively constant, and non-residential energy usage per customer will decline at a rate of approximately 0.3 percent per year. GRU recognized some of the factors that effect the usage per customer which include increasing electricity prices, improved building code, energy efficiency standards and regulations, and Utility-sponsored conservation measures. The Utility also anticipated that in future years, loads associated with EV charging are anticipated to support usage per customer for all classes, most significantly in the residential sector with at-home charging.

For the current 10-year forecast horizon, GRU's number of customers and retail energy sales will grow at an annual average rate of approximately 0.6 and 0.5 percent, respectively. The Utility indicated that its projected growth of retail energy sales is supported by its projected increase in the number of customers and offset negatively by flat or declining energy usage 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 32 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan GRU filed in its 2024 TYSP.

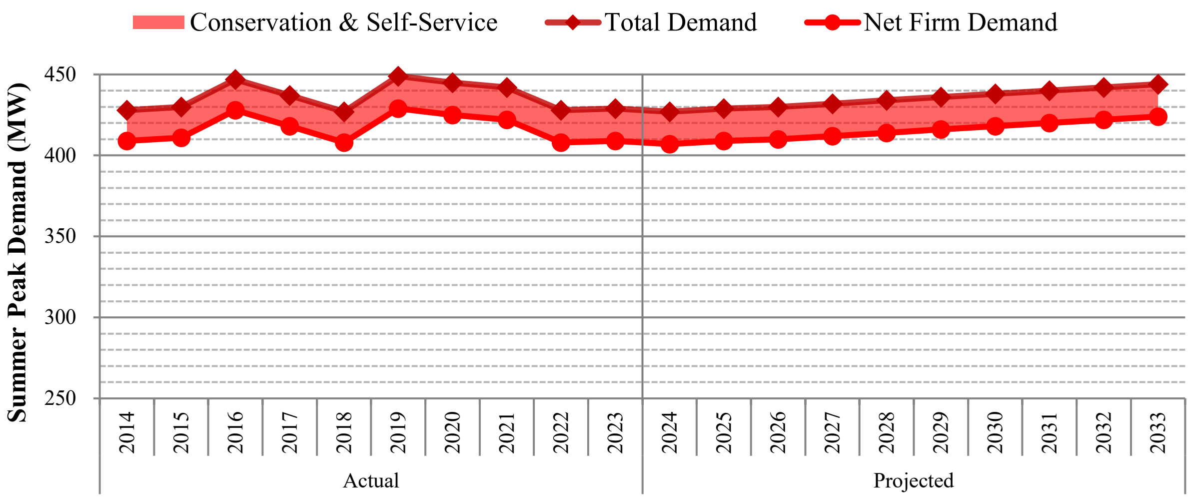
Figure 32: GRU Growth

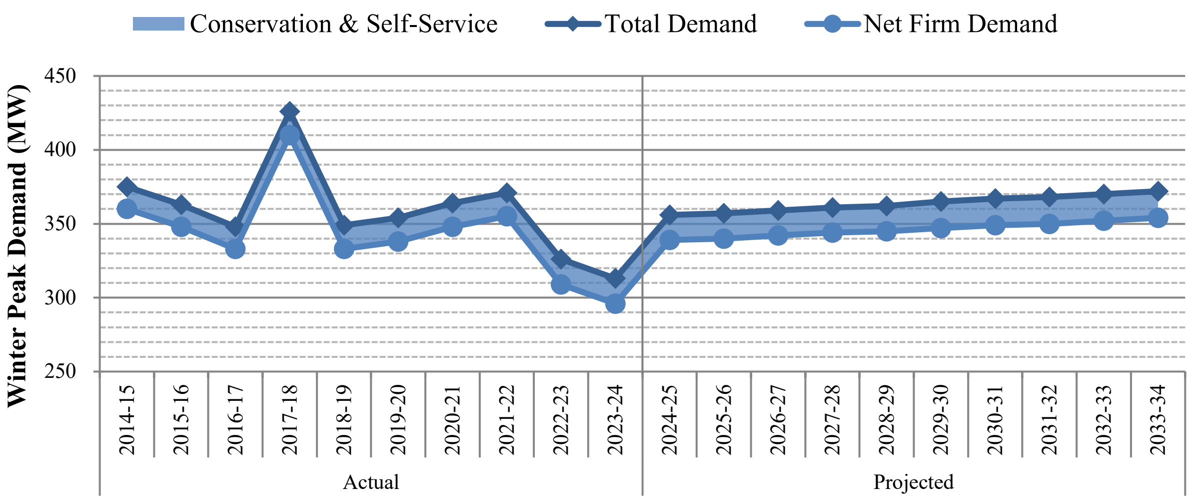


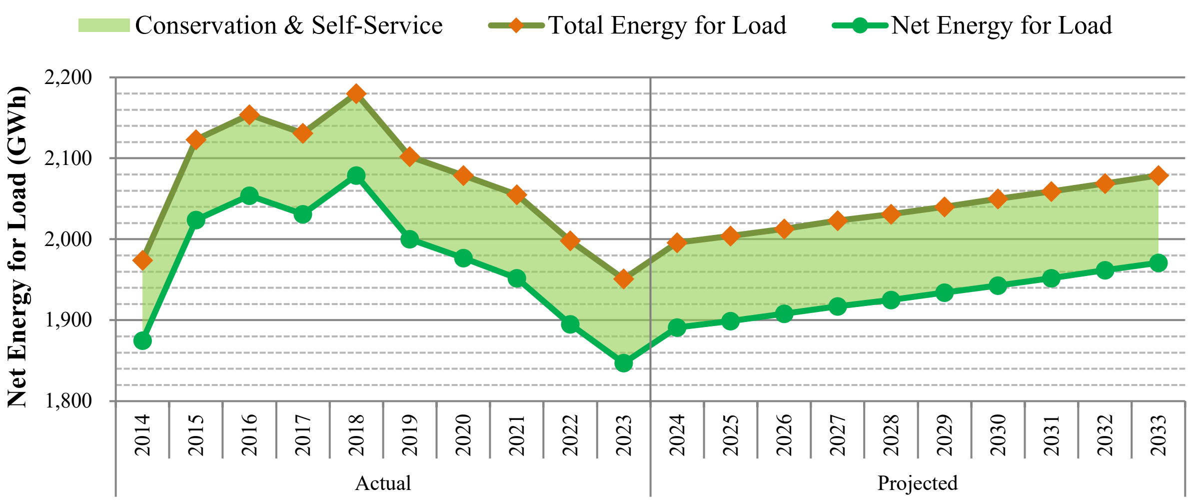
Source: 2024 Ten-Year Site Plan

The three graphs in Figure 33 show GRU's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 33 include the impact of these demand-side management programs.

Figure 33: GRU Demand and Energy Forecasts







Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2022, natural gas and renewables were the primary fuel for energy generation, making up approximately 100 percent of net energy for load. GRU currently has the highest percentage contribution of renewables in Florida for net energy for load, but will fall behind FPL and JEA by 2033.

Table 21: GRU Energy Generation by Fuel Type

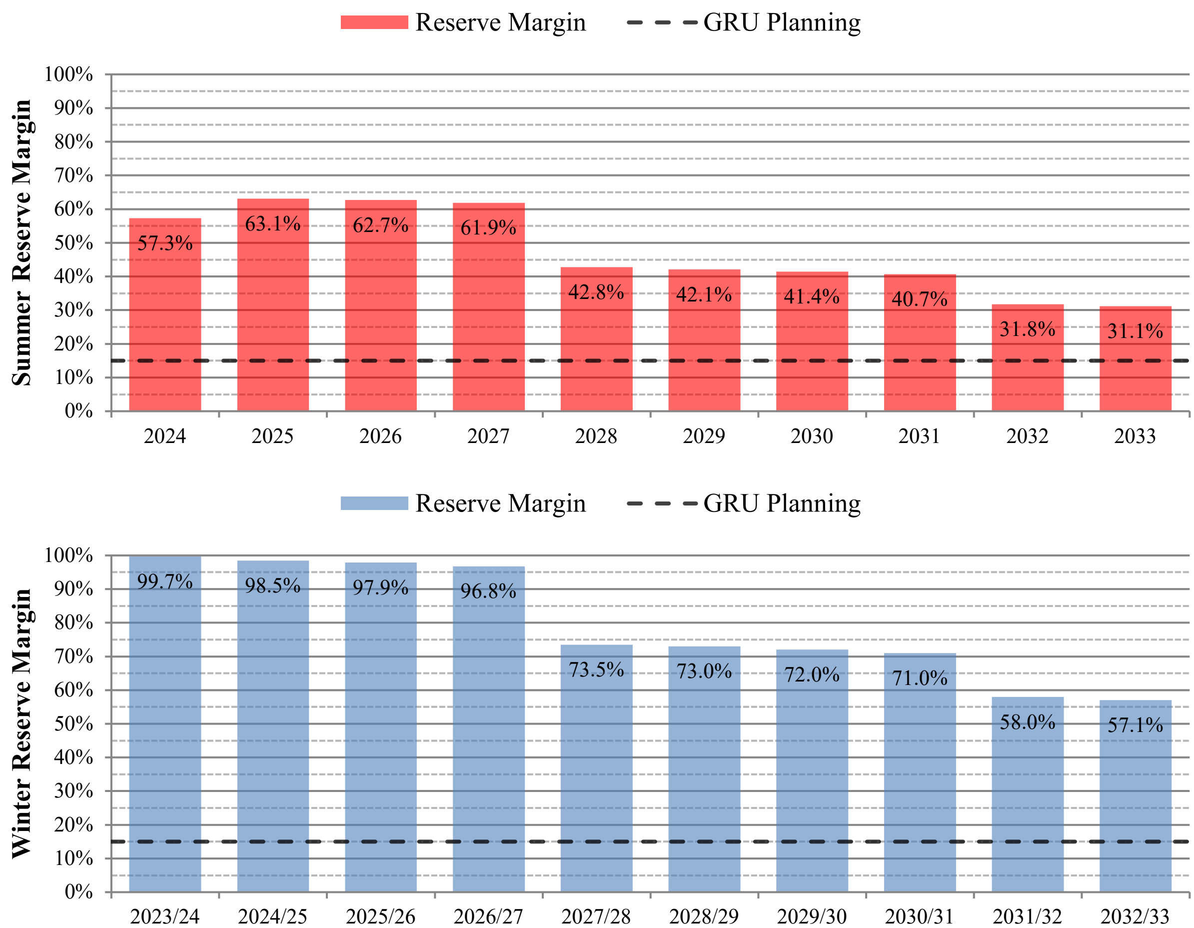
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	1,574	**84.6%**	1,266	**64.2%**
Coal	20	**1.1%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	296	**15.9%**	640	**32.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(29)	**-1.6%**	66	**3.3%**
Total	**1,861**		**1,972**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 34 displays the forecast planning reserve margin for GRU through the planning period for both seasons. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period.

Figure 34: GRU Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

GRU currently plans on retiring three natural gas-fired units, as described in Table 22. All three units, a pair of combustion turbines and a steam turbine, are located at GRU's Deerhaven plant. In addition, GRU entered into a 20 year contract that is expected to deliver an additional 75 MW of solar capacity through a PPA with an expected in-service year of 2025, including a 12 MW battery installation.

Table 22: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2027	Deerhaven Unit FS01	NG ST	76	
2031	Deerhaven Unit GT01 & GT02	NG CT	35	2 Units Total
		Total Retirements	**111**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(111)**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

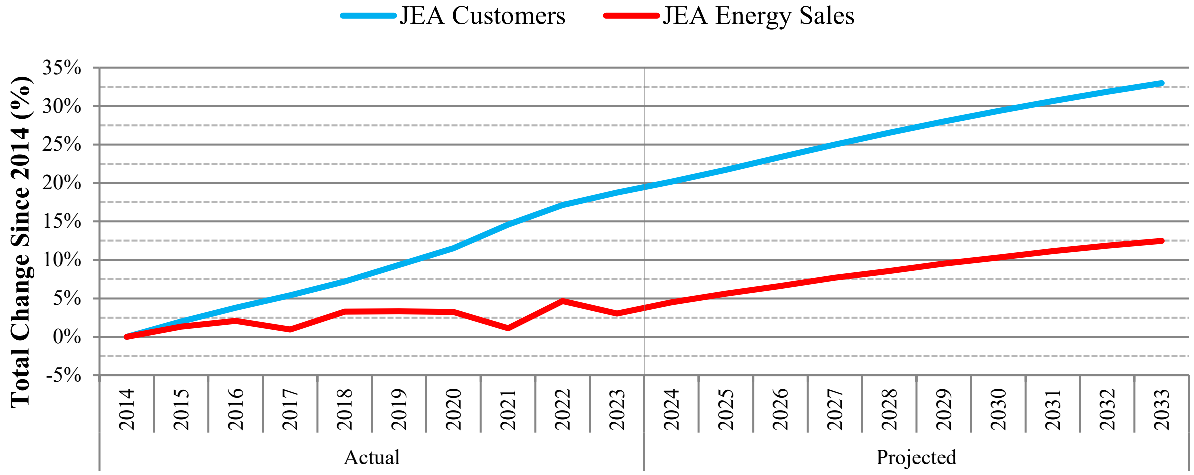
In 2023, JEA had approximately 514,909 customers and annual retail energy sales of 12,295 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Over the last 10 years, JEA's customer base has increased by approximately 18.8 percent, while retail energy sales have increased by approximately 3.0 percent.

JEA utilized various economic and demographic forecasts from Moody's Analytics as the inputs to the Utility's forecasting models. Overall, Moody's Analytics inputs resulted in a forecasted percentage growth for all parameters utilized in JEA's 2024 TYSP which is very similar as compared to the 2023 forecasts. As a result, JEA projected a 1.1 percent growth for residential customers, and 0.3 percent growth for both commercial and industrial customers.

JEA indicated that the Utility-funded demand-side management programs continue to be a contributor to the usage decrease in annual energy use per residential customer. The other contributing factors include customer behavioral changes, increased electric rates, more multifamily housing constructions compared to single-family housing constructions that use less energy per customer. The Utility noted that the US Government's SEER Requirement Changes for 2015, that required new split system central air conditioners to be a minimum 14 SEER, had contributed to the majority of decrease in electricity use per customer over the past years. It further indicated that the new 2023 SEER rating standards, now requiring new air conditioners in Southern states to be a minimum 15 SEER, will continue to contribute to the decrease in electricity usage per customer. For the 2024 TYSP forecasting horizon, JEA expected that the average energy consumption per customer will stay flat for residential customers, decrease for commercial customers with an annual growth rate of negative 0.9 percent, and increase slightly for industrial customers with a rate of 0.2 percent.

For the next 10 years, JEA's forecasting results indicate that the customer numbers will grow at an average annual rate of 1.1 percent; and the retail energy sales will grow at an average annual rate of 0.8 percent. Figure 35 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan JEA filed in its 2024 TYSP.

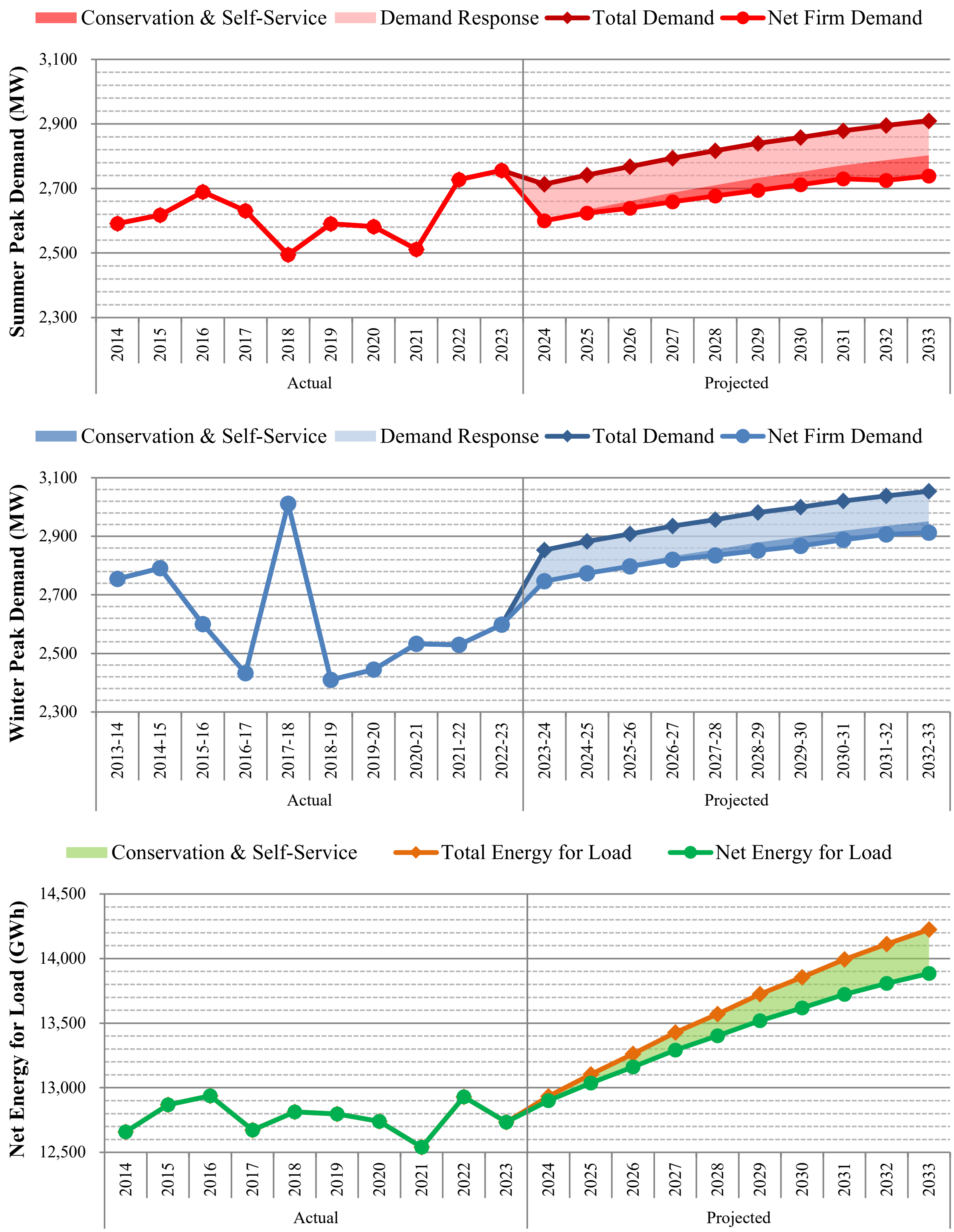
Figure 35: JEA Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 36 show JEA's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. 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 August 2024, the Commission established demand side management goals for JEA for the years 2025 through 2034. In 2025, the Commission will review JEA's plan designed to achieve the Utility's DSM goals. In preparing its 2024 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 2033).

Figure 36: JEA Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. While natural gas was the dominant fuel source in 2023, purchases through the Interchange was JEA's second most utilized energy source. JEA has the highest percentage of energy from other utilities (interchange), primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the Vogtle nuclear Units 3 and 4. JEA's 2024 Ten-Year Site plan projects that a JEA will reduce its use of coal while increasing its renewable fuel source.

Table 23: JEA Energy Generation by Fuel Type

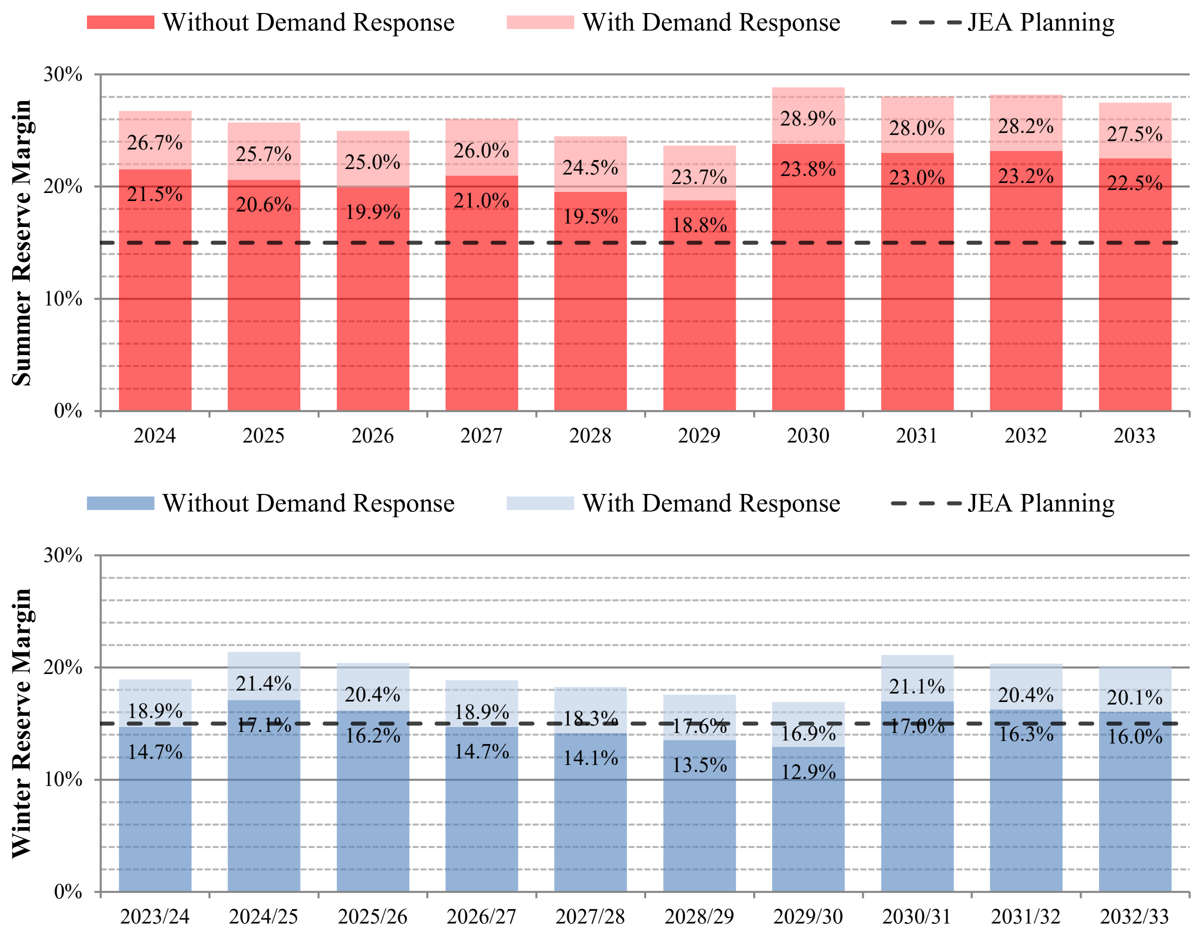
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	7,268	**57.1%**	8,192	**59.0%**
Coal	1,231	**9.7%**	397	**2.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	3	**0.0%**	5	**0.0%**
Renewable	412	**3.2%**	3,146	**22.7%**
Interchange	3,763	**29.6%**	2,080	**15.0%**
NUG & Other	46	**0.4%**	65	**0.5%**
Total	**12,722**		**13,885**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 37: JEA Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

As detailed in Table 24, JEA is retiring Northside Unit 3 and adding an unnamed natural gas-fired combined cycle unit. JEA has entered into a PPA with Municipal Electric Authority of Georgia for firm nuclear capacity, and is currently receiving 100 from Vogtle Unit 3, and anticipates receiving an additional 100 MW from Vogtle Unit 4 in 2024. In addition, JEA is planning to enter into several solar PPAs totaling 1,134 MW. JEA has already entered into PPAs for 420 MW of new solar to be constructed through 2027, and 150 MW of existing solar capacity from FPL. A majority of the PPAs, totaling 559 MW, are planned for 2030. JEA also reported that approximately 140 MW of battery storage would be associated with the solar PPAs.

Table 24: JEA Energy Generation by Fuel Type

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2030	Northside Unit 3	NG ST	524	
		Total Retirements	**524**	
New Units				
2030	Advanced-Class 1x1 CC	NG CC	576	PPSA Approval Needed
		Total New Units	**576**	
		Net Additions	**52**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, LAK had approximately 141,106 customers and annual retail energy sales of 3,311 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Over the last 10 years, LAK's customer base has increased by 13.8 percent, while retail energy sales have grown by 14.1 percent approximately.

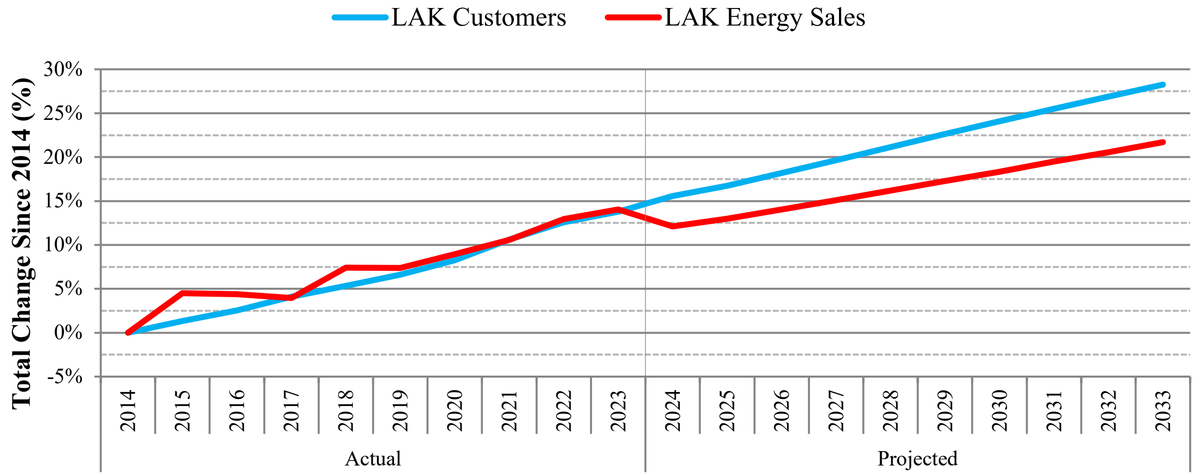
In recent years, LAK's service area in Polk County has seen a boom in e-commerce warehouse development. Notably, Amazon moved its air-hub from Tampa to the Utility's service area in the summer of 2020 and it is continuing to expand. As a result, LAK experienced 1.1 percent total customer growth in 2023, with the commercial rate class growing by 4.3 percent and industrial class growing by 2.0 percent.

Despite customer growth, 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 mix residential building type. The Utility's commercial average energy consumption per customer has also been declining, and this trend is expected to continue. Main contributors to the decline are lighting upgrades, appliance energy efficiency improvements, and the customer adoption of energy management systems. LAK expects a flattening of the trend of LAK's 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 energy use declines. The Utility assumed the impact of conservation programs are already included in the energy sales history and made no additional assumptions regarding their impact.

For the next 10 years, the Utility's forecasts indicate that LAK's number of customers are projected to grow at an average annual rate of approximately 1.2 percent, and its retail energy sales are projected to grow at an average annual rate of approximately 0.9 percent. Figure 38 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan LAK filed in its 2024 TYSP.

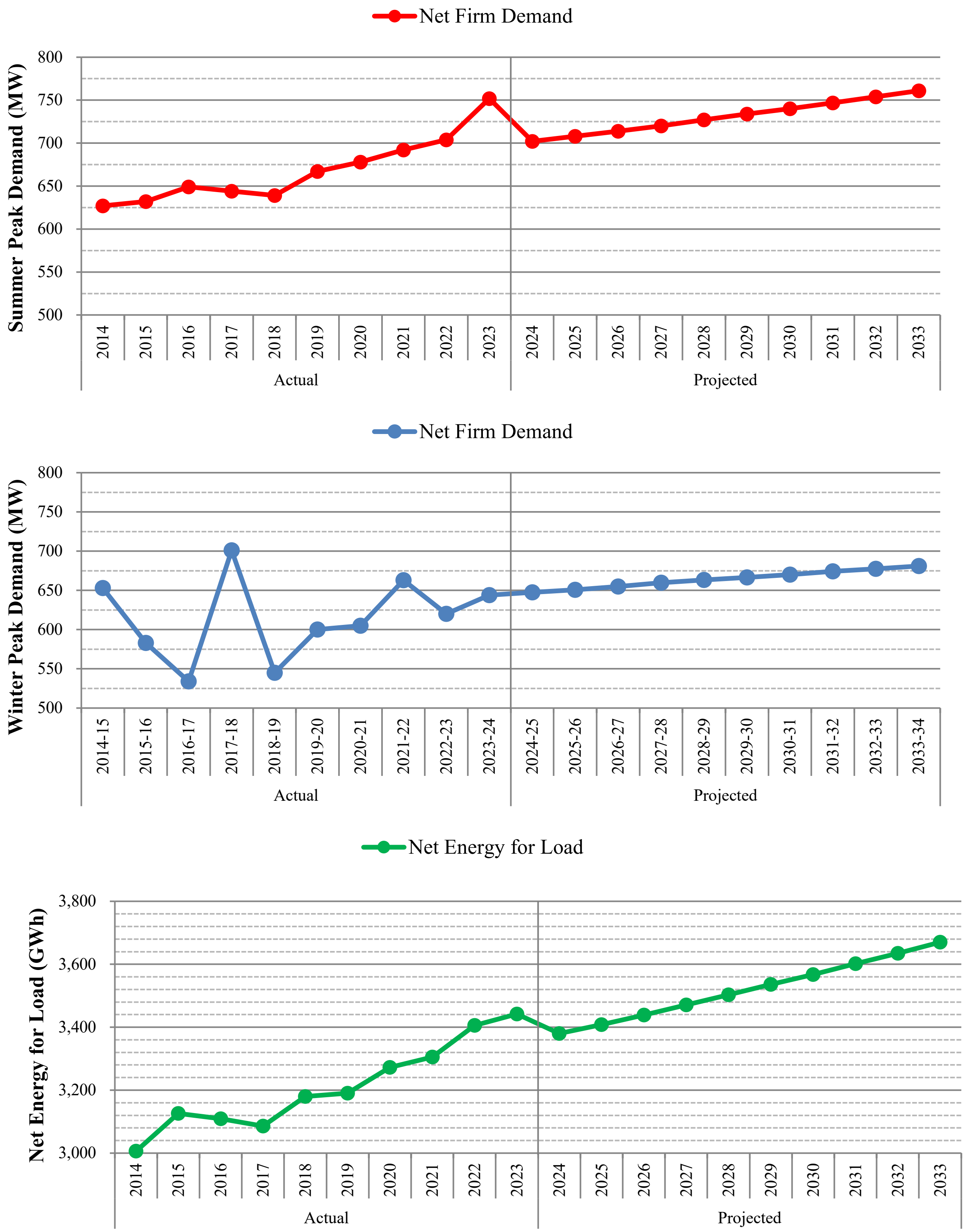
Figure 38: LAK Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 39 show LAK's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 39: LAK Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. LAK uses natural gas as its primary fuel type for energy, with purchases (listed in the NUG & Other category below) representing about 42 percent net energy for load. While natural gas generation is anticipated to increase over the next 10 years, interchange purchases are projected to decrease to about 33 percent, while renewables increase to 5 percent by 2033.

Table 25: LAK Energy Generation by Fuel Type

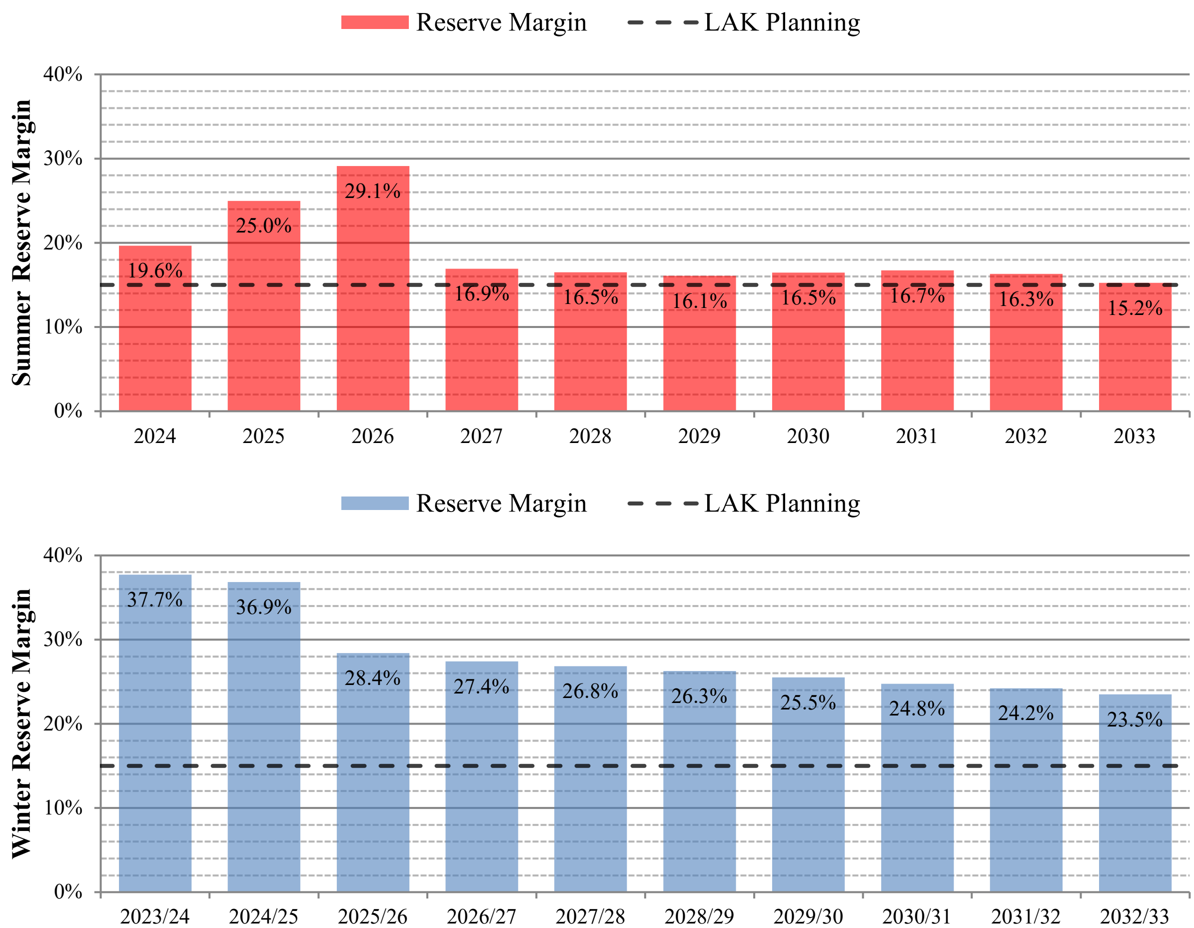
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	1,976	57.4%	2,283	62.2%
Coal	0	0.0%	0	0.0%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	1	0.0%
Renewable	25	0.7%	178	4.9%
Interchange	0	0.0%	0	0.0%
NUG & Other	1,441	41.9%	1,208	32.9%
Total	3,442		3,670	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 40 displays the forecast planning reserve margin for LAK through the planning period for both seasons. The Utility does not offer demand response programs at this time. As illustrated by Figure 40, summer peak demand is the controlling factor for reliability planning for almost all years of the planning period.

Figure 40: LAK Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

LAK plans to add six units during the planning period, as described in Table 26, all natural gas-fired internal combustion engines. LAK is in negotiations for a PPA with Edge Solar for a 75 MW solar facility by 2026.

Table 26: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
Total Retirements			**0**	
New Units				
2024	McIntosh Units ME1 –ME6	NG IC	120	6 Units Total
Total New Units			**120**	
Net Additions			**120**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

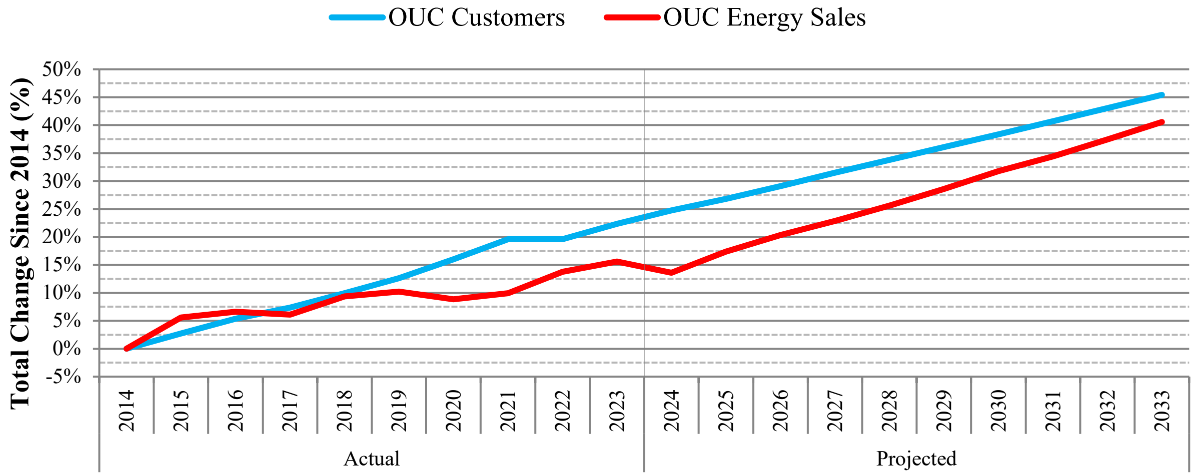
Load and Energy Forecasts

In 2023, OUC had approximately 275,339 customers and annual retail energy sales of 7,155 GWh or approximately 3.1 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 22.3 percent, while its retail energy sales have increased by 15.6 percent, approximately.

OUC experienced a continued decline in weather-normalized average use per residential customer in 2023. 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 usage per customer 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 the pandemic in 2020, but is expected to return to pre-pandemic levels. The Utility's industrial average use per customer increased approximately 1.4 percent annually over the last 10-year period.

Over the forecast horizon, OUC is projecting growth in the number of customers at an average annual rate of 1.7 percent, and retail energy sales at an average annual rate of 2.4 percent approximately. OUC noted that the main contributors to the projected customer growth include the increased population and household numbers in its service area. The main drivers for the projected growth of the energy sales include the recovery from COVID-19 pandemic effects, the projected growth in electric vehicle charging load, and major commercial expansions by Universal Studios and the Orlando International Airport that are largely outside of normal growth. Figure 41 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan OUC filed in its 2024 TYSP.

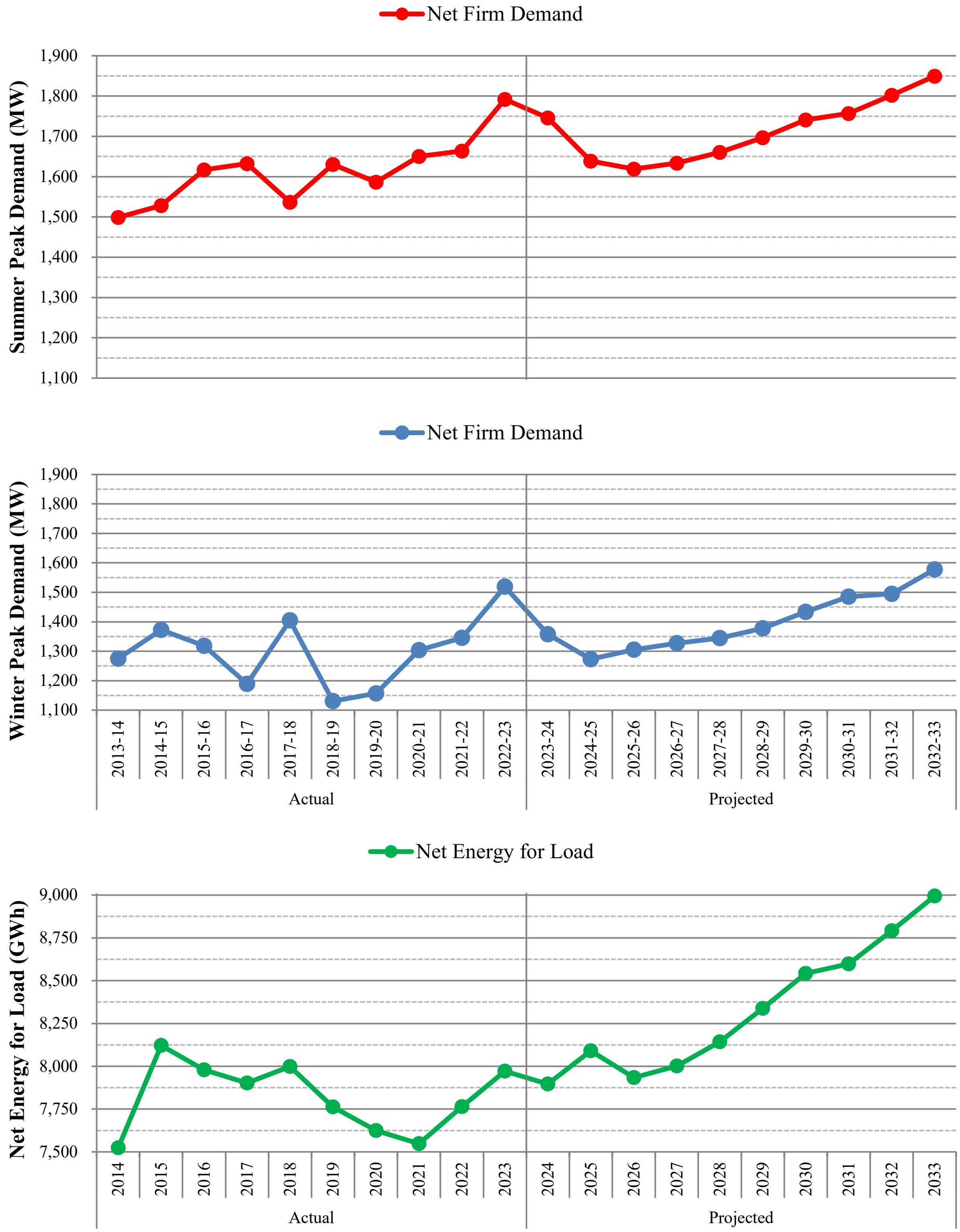
Figure 41: OUC Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 42 show OUC's seasonal peak demand and net energy for load for the historic years of 2024 through 2023 and forecast years 2024 through 2033. 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 August 2024, the Commission established demand side management goals for OUC for the years 2025 through 2034. In 2025, the Commission will review OUC's plan designed to achieve the Utility's 2025-2034 DSM goals. In preparing its 2024 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 2033).

Figure 42: OUC Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 27 shows OUC's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2023, approximately 65 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met approximately 24 percent of the demand. By 2033, OUC projects an increase in renewable energy generation from 5 percent to 50 percent, the second highest in the state. The remainder of energy primarily comes from natural gas and nuclear, with coal generation completely eliminated.

Table 27: OUC Energy Generation by Fuel Type

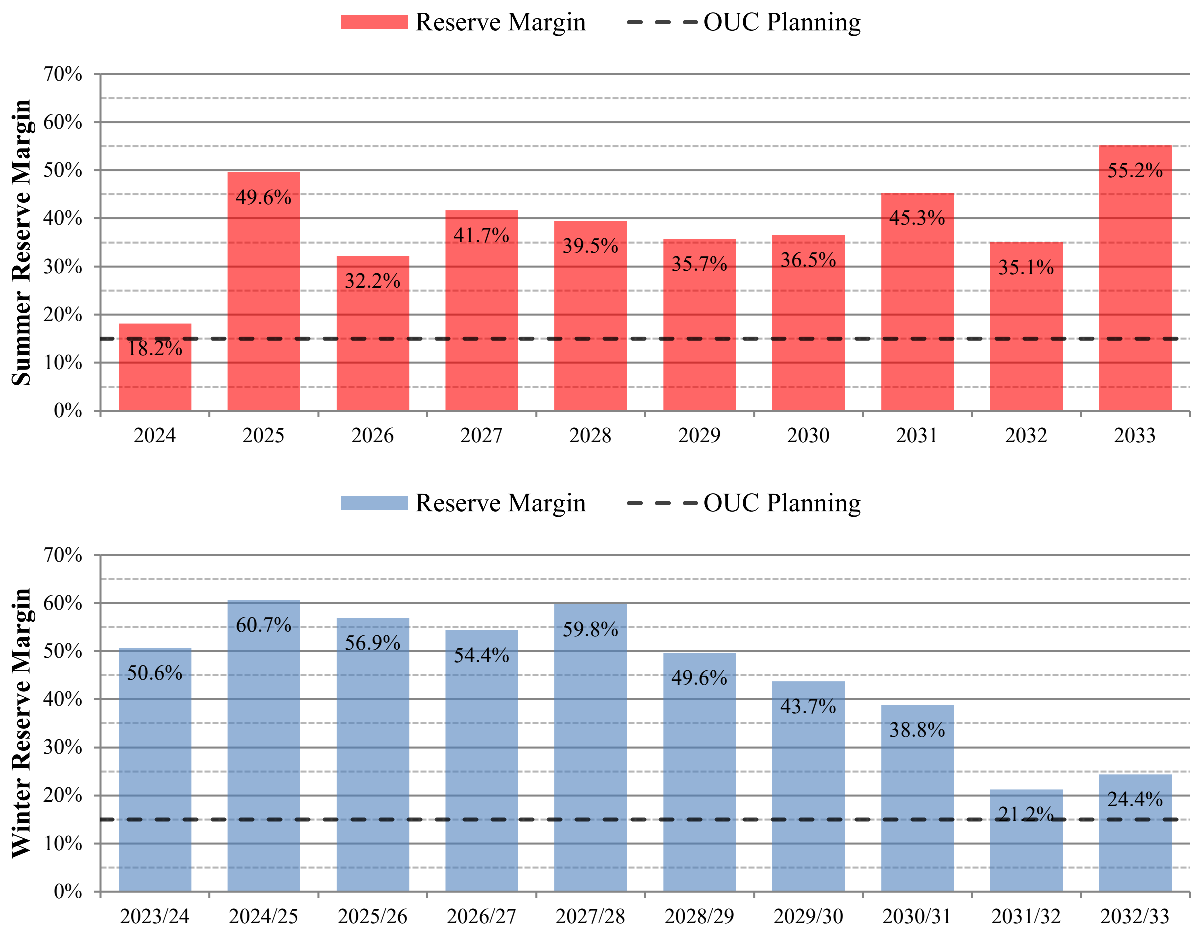
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	5,144	**64.5%**	4,002	**44.5%**
Coal	1,938	**24.3%**	0	**0.0%**
Nuclear	494	**6.2%**	479	**5.3%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	396	**5.0%**	4,513	**50.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,972**		**8,994**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 43: OUC Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

As detailed in Table 28, OUC plans on retiring Stanton Energy Center Unit 1, OUC's oldest coal-fired unit, in 2025. OUC will convert the remaining coal-fired Stanton Energy Center Unit 2 to a natural gas-fired unit by the end of 2027. Transmission upgrades planned for 2025 will allow OUC full access to the firm capacity of their existing Osceola generating unit. OUC anticipates entering into PPAs for a total of 1,267 MW of solar net capacity and 600 MW of battery storage. These PPAs are projected to contribute 559 MW and 600 NW to firm summer peak, respectively. OUC has already signed two of these PPAs, with NextEra for a total of 149 MW of solar capacity with a planned in-service year of 2024.

Table 28: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Energy Center Unit 1	Coal ST	311	Jointly Owned Unit
		Total Retirements	**311**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(311)**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

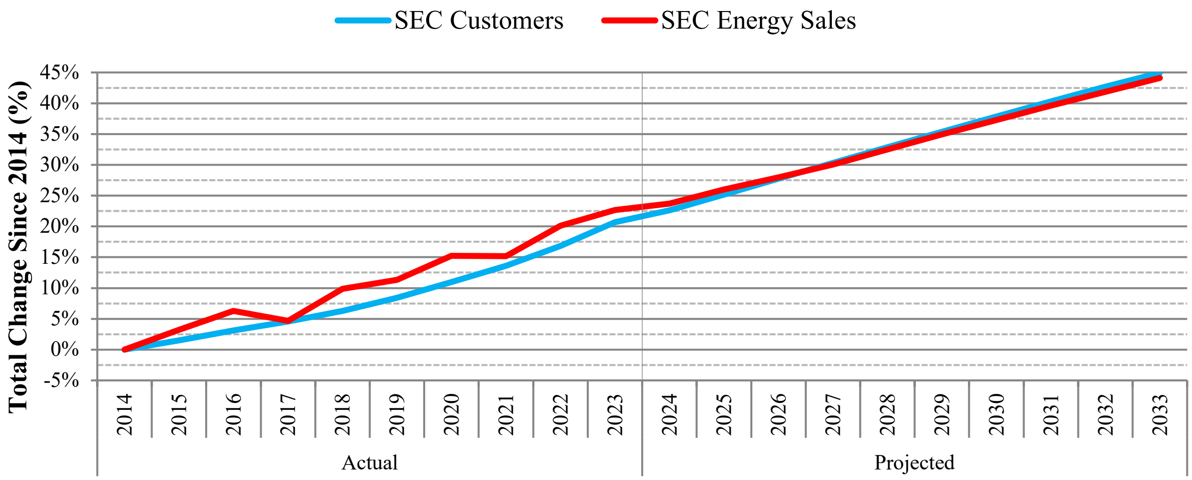
Load and Energy Forecasts

In 2023, SEC member cooperatives had approximately 893,826 customers and annual retail energy sales of 15,895 GWh or approximately 6.8 percent of Florida's annual retail energy sales. Over the last 10 years, SEC's customer base has increased by 20.7 percent, while its retail energy sales have increased by 22.7 percent, approximately.

SEC states that, historically, the consumer base of its 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 during the COVID-19 pandemic. Customer growth and business activity are expected to drive growth of retail energy sales in a positive direction, while downward pressure is also anticipated. The downward pressure is expected to come from flattening and declining residential end-use which is 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 1.9 percent, and an average annual growth rate in its retail energy sales of 1.7 percent. Figure 44 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan SEC filed in its 2024 TYSP.

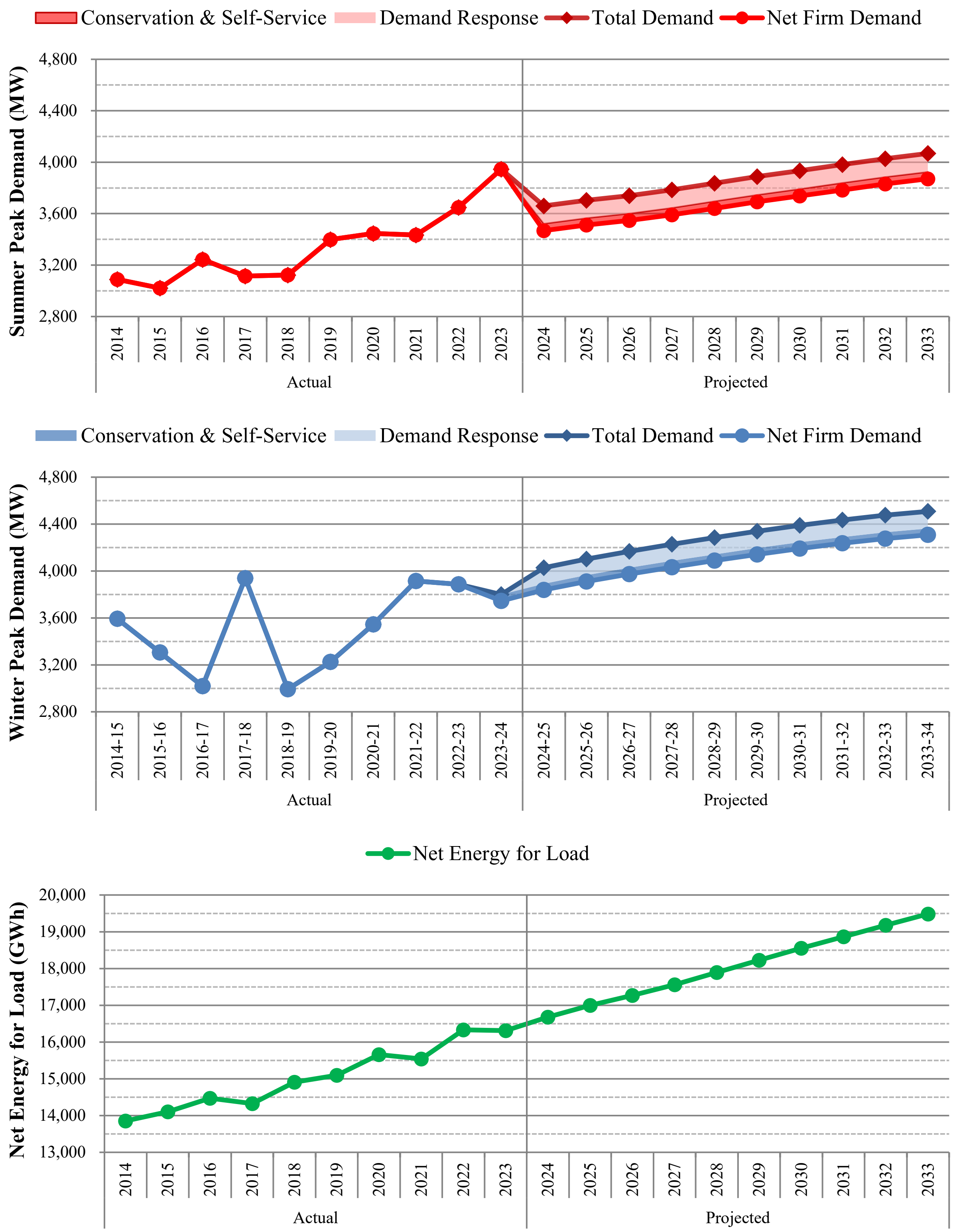
Figure 44: SEC Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 45 show SEC's seasonal peak demand and net energy for load for the historic years 2014 through 2023 and forecast years 2024 through 2033. As SEC is a generation and transmission utility, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 45.

Figure 45: SEC Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 29 shows SEC's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2023, SEC used a mix of natural gas, coal and purchases to meet demand requirements. However, during the planning period, SEC will be switching to mostly self-generation by increasing natural gas usage while reducing coal and purchases. By 2033, natural gas will represent approximately 87 percent of SEC's fuel usage.

Table 29: SEC Energy Generation by Fuel Type

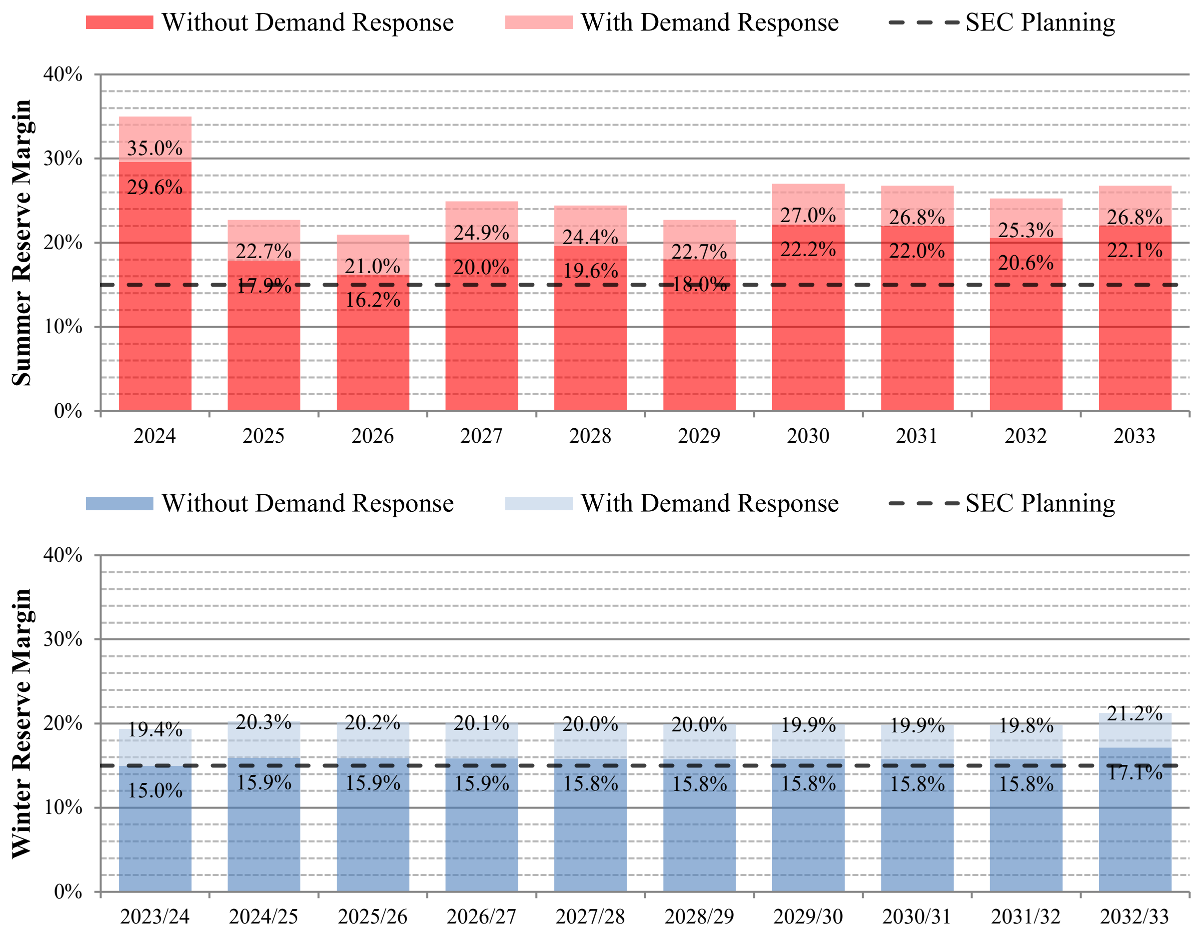
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	8,920	54.7%	16,881	86.6%
Coal	4,896	30.0%	1,366	7.0%
Nuclear	0	0.0%	0	0.0%
Oil	18	0.1%	4	0.0%
Renewable	423	2.6%	738	3.8%
Interchange	141	0.9%	0	0.0%
NUG & Other	1,914	11.7%	495	2.5%
Total	16,312		19,484	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 46: SEC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

SEC plans to add three units during the planning period, as described in Table 30, all natural gas-fired generation. SEC plans to add two combined cycles and one combustion turbine during the planning period. SEC anticipates an additional 300 MW of solar generation through PPAs to become commercially operational by the end of 2024, of which 119 MW will be considered firm for summer peak.

Table 30: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
Total Retirements			**0**	
New Units				
2026	Shady Hills	NG CC	546	PPSA Approved
2029	Unnamed CT	NG CT	317	
2032	Unnamed CC	NG CC	571	PPSA Approval Needed
Total New Units			**1,434**	
Net Additions			**1,434**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, TAL had approximately 119,140 customers and annual retail energy sales of 2,694 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Over the last 10 years, TAL's customer base has increased by approximately 2.1 percent, while retail energy sales have increased by approximately 2.4 percent.

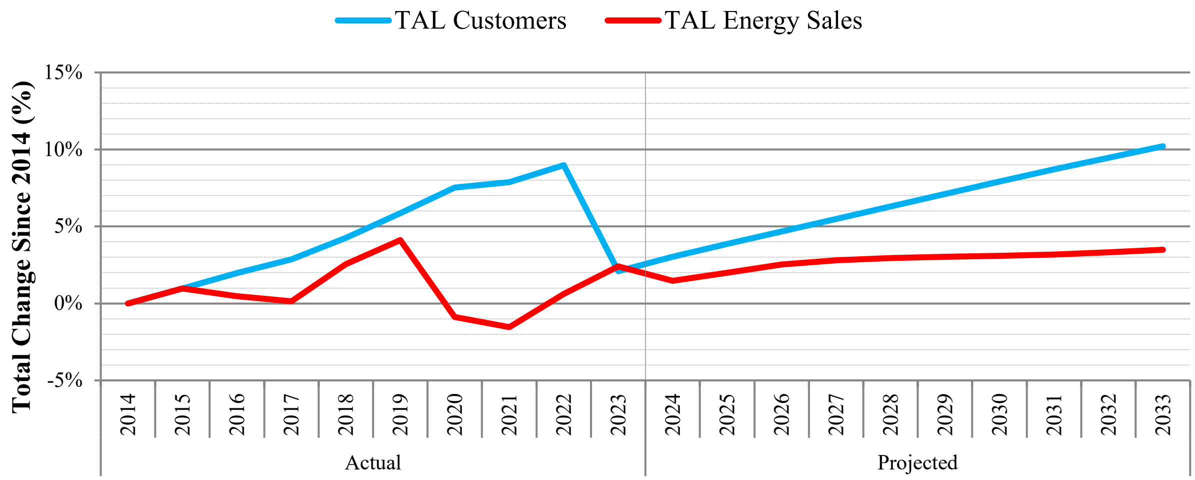
TAL's customer base consists of residential and commercial classes. The total energy consumption associated with the commercial class is higher than that associated with the residential class. The Utility's customer count growth correlates well to the rate of change in Leon County's population, household formation, and economic activity; and, the historical trend and 10 year forecast predict steady growth in its customer counts.

The Utility indicated that its energy efficiency and demand-side management programs have decreased the average residential and commercial demand and energy requirements and are projected to somewhat offset the increased growth from population in residential and commercial customers. Additionally, the Clean Energy Plan, which promotes accelerated installation of distributed solar PV and heightened energy efficiency investment through 2030, is also projected to somewhat offset the Utility's increased load growth from emerging electrification efforts such as electric vehicle charging. The net effect is the average consumption for residential and commercial customers may be approaching its minimum and leveling out over time.

Over the current forecast horizon, TAL is projecting an average annual growth rate of approximately 0.8 percent in its total customer counts, and an average annual growth rate of approximately 0.2 percent in its annual retail energy sales. Figure 47 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan TAL filed in its 2024 TYSP.

TAL implemented a new customer management software in 2022 and completed the transition in 2023. The new software positively affected the customer experience in how they are able to view and pay bills. The side effects of this implementation included some data impacts, such as transitioning from bill-based customer counts to meter-based customer counts, which overall reduced the number of customers in the billing system, and reclassifying some non-demand small commercial to residential classifications. TAL noted that the data collection issues should not persist in 2024 as the software implementation is complete.

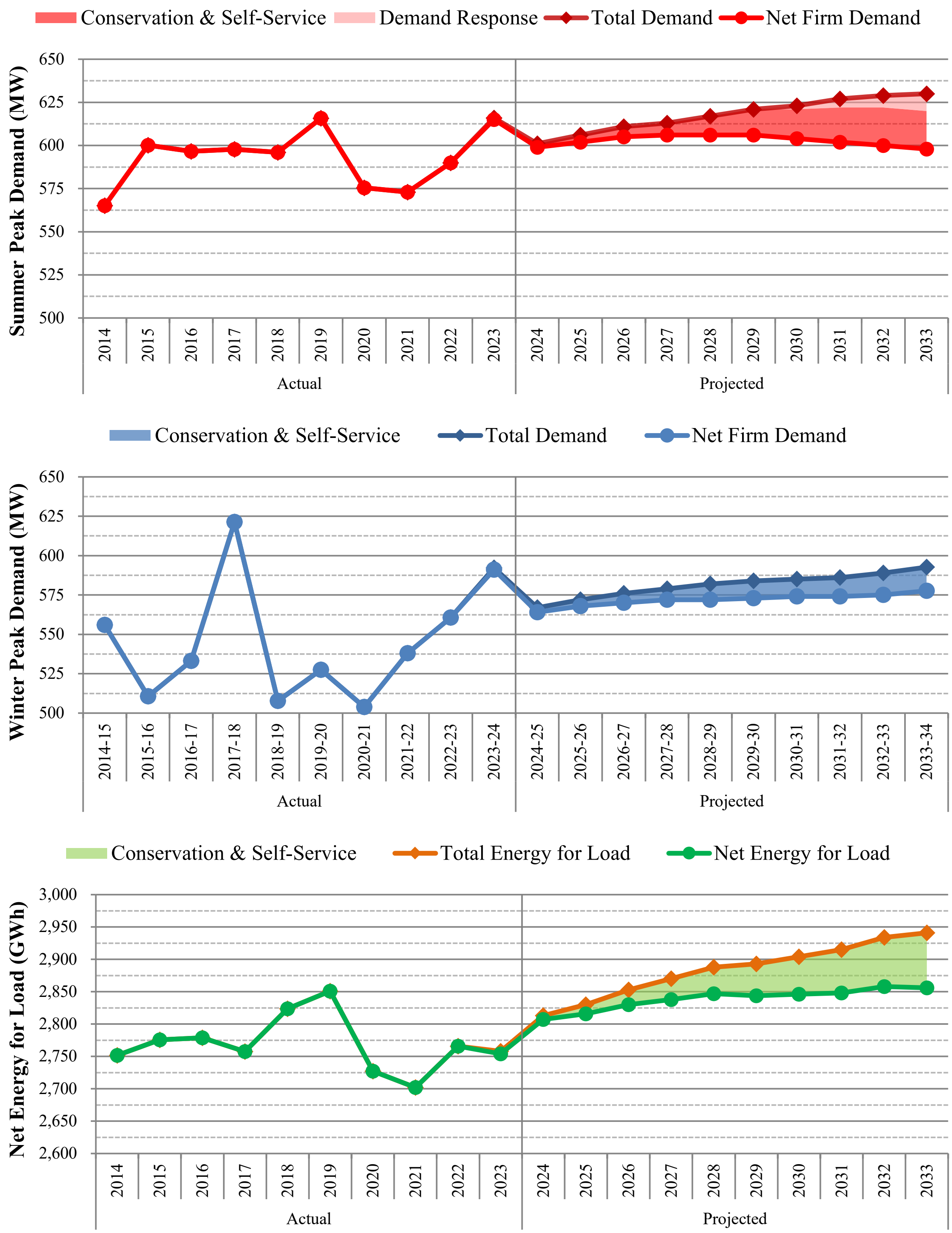
Figure 47: TAL Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 48 show TAL's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently, TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 48: TAL Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 31 shows TAL's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. 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			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	3053	**110.9%**	2,780	**97.3%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.1%**	0	**0.0%**
Renewable	107	**3.9%**	111	**3.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(409)	**-14.9%**	(35)	**-1.2%**
Total	**2,753**		**2,856**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 49: TAL Reserve Margin Forecast

Source: 2024 Ten-Year Site Plan

Generation Resources

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

Attachment 2

State of Florida

Public Service Commission

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

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

DATE: December 12, 2024

TO: Braulio L. Baez, Executive Director

FROM: Cayce H. Hinton, Director, Office of Industry Development and Market Analysis CH

RE: Draft Plan for Assessing the Security and Resilience of Florida's Electric Grid and Natural Gas Facilities against Cyber and Physical Attacks

CRITICAL INFORMATION: Please place on the December 19, 2024 Internal Affairs Agenda. **Commission Approval is sought.** The Plan for Assessing the Security and Resilience of Florida's Electric Grid and Natural Gas Facilities against Cyber and Physical Attacks is due to the Governor, the President of the Senate, and Speaker of the House by January 31, 2025.

Pursuant to Chapter 2024-186, section 20, Laws of Florida, the Commission is required to develop and recommend a plan for conducting an assessment of "the security and resiliency of the state's electric grid and natural gas facilities against both physical and cyber threats." As part of that directive, the Legislature also required the Commission to address "the manner in which information needed to conduct a security and resiliency assessment may be communicated, collected, shared, stored, and adequately protected from disclosure to avoid adverse impacts on the safe and reliable operation of the state's electric grid and natural gas facilities." By January 31, 2025, the Commission is to submit its recommended plan to the Governor, the President of the Senate, and the Speaker of the House of Representatives.

Please place the attached Plan for Assessing the Security and Resilience of Florida's Electric Grid and Natural Gas Facilities against Cyber and Physical Attacks on the December 19, 2024 Internal Affairs. Staff is seeking Commission approval.

Attachment

cc: Mark Futrell, Deputy Executive Director, Technical
Apryl Lynn, Deputy Executive Director, Administrative
Keith Hetrick, General Counsel

Plan for Assessing the Security and Resilience of Florida's Electric Grid and Natural Gas Facilities against Cyber and Physical Attacks

January 2025

TABLE OF CONTENTS

Figure **Page**

Tables **Page**

I. Executive Summary

The Legislature tasked the Florida Public Service Commission (Commission or FPSC), in consultation with the Division of Emergency Management and the Florida Digital Service, to develop and recommend a plan for conducting an assessment of "the security and resiliency of the state's electric grid and natural gas facilities against both physical and cyber threats." Ch. 2024-186, section 20, Laws of Florida.

The Commission recommends that an assessment plan should primarily focus on the following five essential functions of a comprehensive cyber and physical security program:

- Risk Assessment and Mitigation
- Self-Evaluation of Processes and Internal Controls
- Regulatory Compliance
- Information and Operational Technology Protection
- Readiness Planning and Testing

Florida's electric and natural gas utilities recognize they must vigorously address each of these functions in their security programs and have dedicated substantial resources to maintain security and service reliability. Though specific regulatory requirements drive some activities, each utility exercises broad discretion in executing these functions. Utilities' risk profiles, financial resources, and subject matter expertise vary widely, as do the protection programs they deploy.

A. Scope

In developing a plan for assessing protections against cyber and physical attacks, the Commission recommends that the scope be focused upon these elements:

- The present and near-future challenges Florida's electric and natural gas utilities face within the constantly-evolving cyber and physical attack threat landscape. A description of the present threat landscape is provided in **Chapter II** of the report.

- The regulatory approach and compliance requirements presently in use by federal and state regulators to govern and assess the security and resilience of the electric and natural gas industries. **Chapter III** provides a description of the various governmental agencies involved in oversight of cyber and physical security protection, and their respective roles.

- The industry best practices regarding cyber and physical security currently being deployed by electric and natural gas utilities to maintain the security and resilience of critical assets and operations. The elemental functions and activities necessary for protection against attacks are discussed in **Chapter IV**.

- The challenge posed by the sensitive nature of utility cyber and physical protection efforts and the need for an assessment process to balance confidentiality concerns against statutory public disclosure requirements. These issues are discussed in **Chapter V** of the report.

B. Process Recommendations

In preparing an assessment plan, the Commission observes that the following initial steps will be required:

- Identify and define the appropriate role for Florida's state government to play in assessing the status of protections against cyber and physical attacks.

- Identify the duties, skillsets, and resources necessary to perform this defined role and assign responsibilities among state agencies or create a new organizational structure under the auspices of the State of Florida.

- Develop an assessment methodology that will overcome challenges posed by the highly sensitive nature of confidential utility information.

A collaborative approach to the assessment is recommended, seeking input and cooperation from utilities. Since the subject matter inherently involves a high degree of sensitivity and confidentiality, the assessment team would face challenges protecting the security of information. Fostering mutual trust and candor with Florida utilities would be essential. **Chapter V** of the report presents the Commission's analysis of these inherent confidentiality issues.

The Commission suggests a management audit methodology be used. The Commission's ongoing management audits, which began in 2013, have successfully monitored the status of the cyber and physical security protections of Florida's large electric utilities. Cooperation and extensive input from utilities will be vital to an assessment.

If a more hands-on, technical assessment is deemed necessary, the Legislature should assess the capabilities and skill sets available from state agencies. The use of outside subject matter expertise may be advisable.

C. Assessment Plan Recommendations

The Commission recommends an assessment plan should primarily focus on the following five essential functions necessary for maintaining comprehensive cyber and physical security programs:

- Risk Assessment, Monitoring, and Mitigation
- Self-Evaluation of Processes and Internal Controls
- Regulatory Compliance

- Information and Operational Technology System Protection
- Readiness Testing Activities

Within these five functions, the Commission recommends consideration of the following 16 descriptions of essential activities and approaches that are characteristic of effective utility cyber and physical security programs. Evaluation of the extent to which a utility has prioritized and undertaken these activities will provide the basis for assessing its preparedness against threats.

Risk Assessment, Monitoring, and Mitigation

Comprehensive approach to enterprise risk assessment and prioritization of responses

Ongoing monitoring of risks and development and execution of mitigation efforts

Self-Evaluation of Processes and Internal Controls

Risk-based program of internal audit activities to assess adequacy and effectiveness of internal controls and procedures

Ongoing self-evaluation of rigor and development of the cyber and physical security organization

Ongoing self-evaluation of voluntary adherence to National Institute of Standards and Technology (NIST) Cybersecurity Framework

Regulatory Compliance

Compliance with Federal Energy Regulatory Commission (FERC)-approved North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) reliability standards and North American Energy Standards Board (NAESB) business practice standards

Compliance with applicable rules and regulatory requirements of Department of Homeland Security (DHS), Critical Infrastructure Security Agency (CISA), Transportation Security Administration (TSA), and Department of Energy (DOE)

Compliance with applicable state statutes, FPSC rules and orders, and participation in Commission's periodic operational reviews of cyber and physical security protections

Information and Operational Technology System Protection

Ongoing monitoring of critical systems access authorization for utility and third-party personnel, and through password and multi-factor authentication control procedures

Ongoing monitoring of server and application network environment configuration changes, system updates and patching, and maintaining records of Information Technology (IT) and Industrial Control Systems/Operational Technology (ICS/OT) system events and disruptions

Coordinated protections and separation of IT and ICS/OT systems

Rigorous supply chain screening and protection controls including upstream verification of vendor sourcing through software and hardware bill of materials, and damage protection contract language

Application of endpoint detection and response and threat-hunting tools (provided in-house or by consultants)

Readiness Testing Activities

Response and recovery planning, preparation, and updating of post-incident response and recovery plans

Testing attack readiness through facilities inspections and simulation exercises

Collaboration and information sharing through industry associations, law enforcement agencies, and Information and Sharing and Analysis Centers (ISACs)

II. Background and Perspective

A. Threat Landscape

The worldwide cyber and physical attack threat landscape for critical infrastructure involves various categories of malicious actors who deploy constantly-evolving attack vectors. Threat actors constantly develop methods of intrusion and refine existing ones. Targeted entities respond, attempting to detect, defeat, and ultimately prevent attacks of known types while attempting to catch up with new attack methods.

High-value targets within Florida's critical infrastructure sector include manufacturing, financial services, government, healthcare, and utilities. Several categories of malicious actors possessing differing levels of ability and sophistication maintain non-stop barrages of malicious probing. Collectively this activity takes the form of millions of daily intrusion attempts from varied techniques, such as simple phishing, unauthorized breach of IT and ICS/OT systems, data theft, malware insertion, and supply-chain infection.

In targeting electric and natural gas utilities, potential nation-state actors could seek out targets with the largest potential impact. By triggering cascading outages of portions of the national Bulk Electric Supply (BES) or disrupting the network of interstate natural gas transmission pipelines, actors could cripple parts of the U.S. for extended periods. Though generation reserve margins and intentional network layout redundancy provide a degree of protection, widespread extended electrical outages are more than theoretical possibilities. Specifically, BES interstate transmission lines and substations present the most impactful potential targets. As will be discussed in **Chapter III,** security and operation of these assets are largely subject to federal jurisdiction by agencies such as FERC, DOE, and DHS.

In response to the challenging threat landscape, Florida utilities are dedicating extensive resources to provide protection, detection, and recovery readiness. Ongoing risk assessments and security controls preparation and testing are conducted. Large utilities maintain a defense-in-depth strategy deploying sizeable staffs of cyber technology professionals, cooperating with relevant federal agencies to comply with rules and statutes. They are also scrutinizing supply chain vulnerabilities, making use of smart technology, and performing ongoing self-assessments.

1. Nation-State Threats

A growing number of known and suspected nation-state actor organizations pose the most serious threat to U.S. critical infrastructure. They wield substantial technical expertise and resource backing. The most active and sophisticated cyber attack organizations are sponsored by Russia, the Peoples Republic of China, the Islamic Republic of Iran, and the People's Democratic Republic of Korea.

Motivated politically, nation-state threat groups seek to disrupt operations, cause physical damage, steal intellectual property, and maintain long-term surveillance, often from within infiltrated IT systems. These activities present a serious national security risk that is managed by the Department of Defense (DOD), and federal intelligence agencies such as the Federal Bureau of Investigation (FBI).

2. Other Criminal Threats

Many cybercriminal threat actors deploy most of the same tactics as nation-state actors, but focus on generating financial gain through cyber attacks. This category of threat actors may have no political or social change motivation, but they may also provide services for hire to nation-states to assist in malware and ransomware attacks.

Ransomware has grown as an attack vector, leveraging system intrusions to yield payment of sizeable ransom demands. Following an intrusion, the threat actor succeeds in denying use of a system or application, while threatening to extract and release or destroy confidential information. As in human kidnapping cases, the intruder makes payment demands, provides instructions, and applies deadline pressure to rush the victimized entity to respond. A succession of threatened actions are presented to obtain compliance, though some may be calculated bluffs.

The FBI is the lead federal agency for investigating cyber attacks and intrusions. FBI investigations have led to the recovery of some ransom payments. However, once ransom demands are paid, it remains to be seen whether the attackers keep their promise to re-instate the denied system access or recover captured data. In some cases, where attackers kept promises to restore system use or return stolen data, they have issued statements that the intrusion was only executed for financial motives and not to cause damage or unrest.

B. Noteworthy Cyber and Physical Attacks

To date, despite the barrage of attempts and intrusions that have impacted various industry sector operations worldwide, no cyber or physical attack on the U.S. electrical grid has resulted in significant extended customer outages.

All attacks can provide lessons about the methods and capabilities of attackers. Several notable attacks within the U.S. and elsewhere are highlighted below as examples of various cyber and physical attack vectors, and the varying degrees of impact.

1. Russian Cyber Attacks on Ukraine

In 2015 and 2016, the “Sandworm” threat group, associated with the Russian Federation intelligence agency, triggered power outages in Ukraine using malware. Attackers remotely switched off 30 substations by manipulating three Ukrainian distribution utilities’ control systems. Power was interrupted for approximately three hours system-wide and about 230,000 customers lost power for up to six hours. In 2016, a fully-automated second cyber attack gained access to the Ukrainian utilities’ networks. Sandworm used malware to attack a transmission system control center causing a portion of Kiev to lose power for an hour.

In April 2022, the Computer Emergency Response Team of Ukraine reported that Sandworm targeted a high-voltage electrical substation in Ukraine once again using malware. Sandworm planted the malware on systems within a regional Ukraine energy firm and moved laterally from the IT network. The attempt appeared to target the ICS/OT network with intent to–send commands to substation devices controlling the flow of power. The cyber attack was detected and mitigated before a blackout occurred that could have potentially impacted up to two million people. This incident underscores the national security implications of cyber attacks.

2. SolarWinds

In December 2020, the most widespread supply chain malware attack to date in the U.S. was discovered. Malicious actors, directed by the Russian Foreign Intelligence Service, penetrated U.S. software developer SolarWinds, inserting malware into an update being developed for distribution to customers using SolarWinds' Orion business software. The supply chain attack allowed hackers to access the network of U.S. cybersecurity firm FireEye, which provides hardware, software, and services to investigate cybersecurity attacks and protect against malicious software. FireEye detected the supply chain breach and recognized that attackers entered through a backdoor in the SolarWinds software via an update. Once the update was sent to nearly 18,000 SolarWinds customers, the infection (since dubbed SUNBURST) rapidly spread worldwide.

Affected organizations worldwide included NATO, the U.K. and U.S. governments, the European Parliament and Microsoft. SolarWinds stated that its customers included 425 of the U.S. Fortune 500 companies, the top ten U.S. telecommunications companies, electrical utilities, the top five U.S. accounting firms, all branches of the U.S. Military, the Pentagon, the State Department, and hundreds of universities and colleges worldwide. The malware was imbedded in the IT/OT systems of the impacted organizations and allowed the attackers to transfer and execute files, as well as profile and disable system services. Mitigation actions included rebuilding systems and improving threat detection and vulnerability testing. SolarWinds has since introduced new software development practices and technologies to strengthen its cybersecurity protections.

3. CrowdStrike Falcon Software Release

CrowdStrike offers Falcon, which is an endpoint detection and response software platform that uses artificial intelligence and machine learning to protect customer systems from the latest advanced threats. In February 2024, CrowdStrike developed and tested new software for Microsoft Windows and other systems that was integrated into the Falcon platform.

In July 2024, CrowdStrike released the software update, and an undetected error caused major disruptions to systems supporting aviation, banking, healthcare, and other industries. The effects of the incident were worldwide, impacting 8.5 million Windows devices and other IT systems. Remediation costs exceeded $700 million. Though this incident did not involve malicious actors like the SolarWinds "SUNBURST" supply chain attack, it illustrates the wide reach of a successful intentional attack.

CrowdStrike has deployed process improvements and remediation steps, and its peer-reviewed analysis concludes that "the incident is not exploitable in a way that achieves privilege escalation or remote code execution."

4. Colonial Pipeline

On May 7, 2021, Colonial Pipeline, a gasoline and jet fuel system serving the southeastern U.S., suffered a ransomware cyber attack. According to the FBI, the attack was the work of "REvil," a

Russian-based hacking organization, and a closely-associated ransomware group known as "DarkSide."

Colonial shut down its pipeline to contain the attack and prevent possible system damage. While the OT systems were not affected, the company's IT billing system was compromised. The six-day shutdown caused national impact and was the most successful cyber attack to date on a U.S. energy sector infrastructure target. Since a similar attack could also be executed against a large natural gas pipeline, the Colonial event heightened concerns about preparedness of natural gas pipeline companies.

Within several hours of the attack, Colonial paid the requested ransom of 75 bitcoins worth $4.4 million. The hackers did provide Colonial Pipeline the necessary software application to restore its network, but the network still operated very slowly. The restart of pipeline operations began at 5 p.m. on May 12, ending a six-day shutdown. On June 7, the Department of Justice (DOJ) announced that it had recovered 63.7 bitcoins worth $2.3 million of the company's payment, leaving Colonial with a loss of $2.1 million. Additionally, the Pipeline and Hazardous Materials Safety Administration (PHMSA) penalized Colonial $986,400 for control room management failures.

5. City of Oldsmar, Florida Water Plant ICS/OT Attack

In February 2021, the drinking water treatment facility for the City of Oldsmar, Florida was the target of a cyber attack. The municipally-owned facility provides water to businesses and 15,000 residents in Pinellas County, Florida. Unidentified cyber actors obtained access to the Supervisory Control and Data Acquisition (SCADA) system used for real-time monitoring of processes that control operational devices (e.g., pumps, switches, and valves). They accessed SCADA by exploiting cybersecurity weaknesses such as poor password security, an outdated operating system, and unprotected internet-based remote access software. This access enabled the cyber actors to increase the amount of caustic sodium hydroxide (lye) used in the water treatment process. Plant personnel immediately noticed the change in dosing amounts and corrected the issue before the SCADA system's software detected the manipulation. No customers or company personnel were harmed. Oldsmar's treatment process remained unaffected and continued to operate as normal, but the incident provided motivation nationwide for small water utilities to address the very basic protection weaknesses that were exploited.

6. PIPEDREAM Malware Detected

"PIPEDREAM" is an ICS/OT malware attack framework with primary focus on critical infrastructure equipment and related technologies in oil, gas, and electric power operations. PIPEDREAM has been credited to a group named CHERNOVITE, which is believed to be a Russian state-sponsored threat actor. According to the Critical Infrastructure Security Agency (CISA), advanced persistent threat actors have exhibited the capability to gain full system access to multiple ICS/SCADA devices. With access to ICS/SCADA devices, attackers could move laterally within the OT network to disrupt critical functions or devices.

After initial discovery in April 2022, a cybersecurity threat hunting consultant continued to observe and track PIPEDREAM to determine its capabilities and source. Natural gas and power generation industries may have been targeted.

The discovery of PIPEDREAM is the first instance of pre-emptive detection of a major potential attack targeting ICS/OT. No damage or interruption of operations was caused, but the discovery of this threat has prompted widespread response by potential targets.

Threat groups employing the PIPEDREAM malware appear to be learning from each other, and adopting tactics from previous attacks. Potential targets continue to proactively perform mitigation activities, such as monitoring their industrial environments for vulnerabilities, conducting active threat detection activities, reviewing cybersecurity advisories, and tracking recent intrusion tactics.

7. Physical Attacks on Substations

An April 2013 attack on Pacific Gas & Electric's Metcalf transmission substation near San Jose, California increased concerns about physical attacks on utility infrastructure. At least one shooter fired a rifle through a substation fence under cover of darkness resulting in more than $15 million in damage to 17 transmission transformers. PG&E was able to avoid any customer outages by rerouting its power supply. After the attack, FERC created CIP-014 imposing mandatory physical security standards for substations.

A few similar attacks have occurred in recent years. In December 2022, a coordinated physical security attack disabled two substations in Moore County, North Carolina. Rifle fire was used to damage critical substation components leaving about 45,000 customers without power. Service to all customers was restored within five days. The attack is being investigated by local, state, and federal law enforcement.

In 2022, a single shooter attacked an electric substation in North Dakota with a high-powered rifle causing $1.2 million in damage and power outages to 240 customers. The same shooter was eventually arrested after causing $450,000 of damage in 2023 to transformers at a pump station of the Keystone Pipeline in South Dakota. Though power outages in these attacks have not been significant, there is a substantial cost and supply chain lag time in replacing large substation transformers.

III. Current Oversight and Protections

A. Federal Jurisdiction

Several federal regulatory agencies have issued cyber and physical security standards and guidelines. Some of the standards are mandatory while others are voluntary. The responsibilities of these agencies overlap to an extent and continue to evolve. A simplified overview of the federal agency roles in cyber and physical security is presented in **Figure 1.**

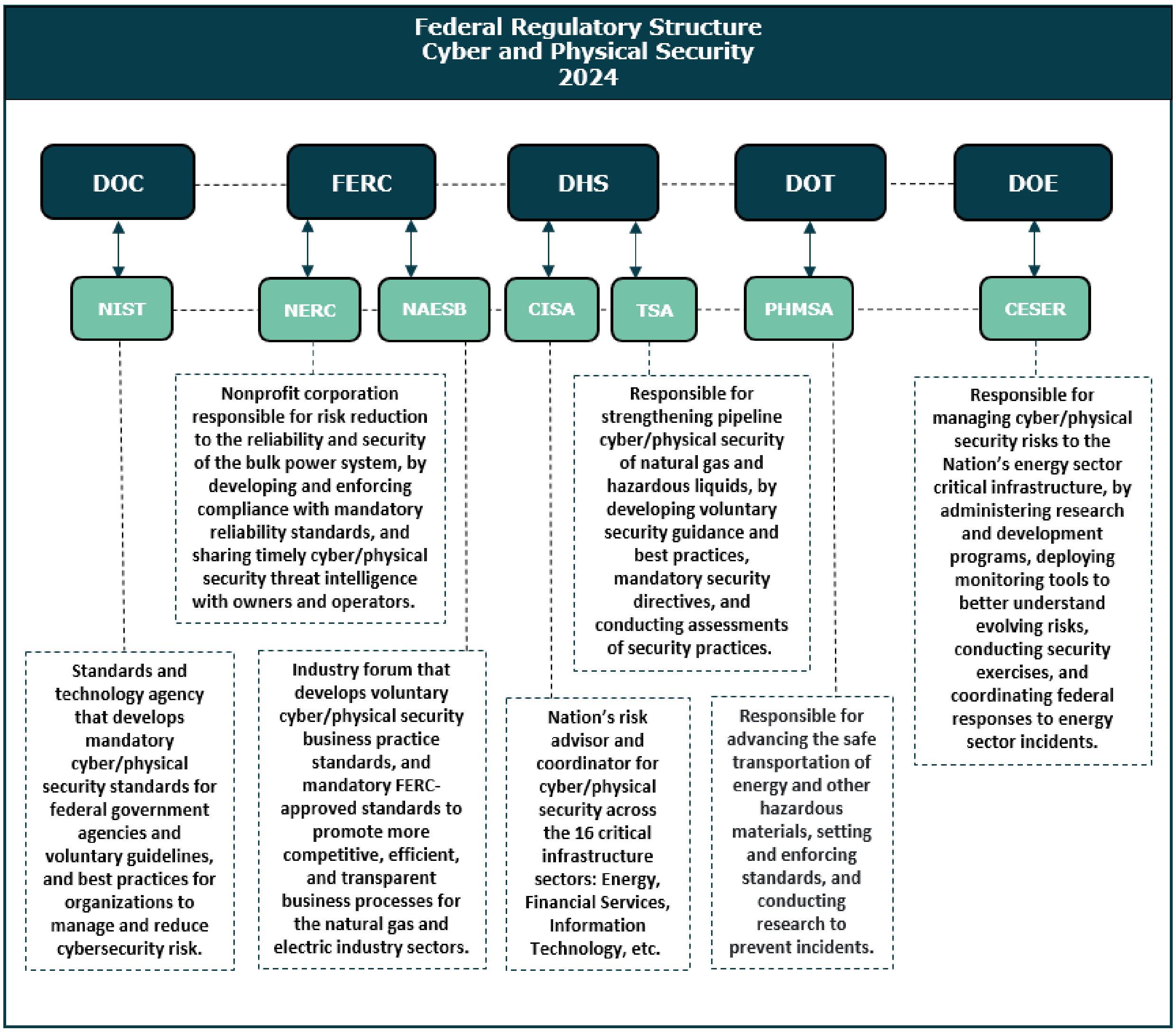


Figure 1

1. National Institute of Standards and Technology (NIST)

NIST, an agency within the Department of Commerce, is responsible for developing cyber and physical security standards, guidelines, best practices, and other resources for public and private-sector entities. The amended Federal Information Security Modernization Act of 2014 (FISMA) designated NIST as the lead federal agency to develop and promote technology standards and guidelines. In response, NIST developed the framework for improving critical infrastructure cyber and physical security needed for FISMA compliance. The NIST Cybersecurity Framework is a set of voluntary best practices, standards, and recommendations to help owners and operators of critical infrastructure to manage and reduce their cyber and physical security risk and protect their networks and data.

Table 1 depicts the NIST Cybersecurity Framework's core functions and categories of activity. The framework outlines cybersecurity capabilities, projects, processes, and daily activities into six functions and 22 categories of activity. The six elemental functions (govern, identify, protect, detect, respond, and recover) provide a high-level view of an organization's functions and objectives for managing cybersecurity risk. Within these functions, the framework identifies 22 categories of activity essential to maintaining effective cybersecurity and physical security programs.

NIST Cybersecurity Framework 2024	
Function	**Categories**
Govern	*Organizational Context *Risk Management Strategy *Roles, Responsibilities, and Authorities *Policy *Oversight *Cybersecurity Supply Chain Risk Management
Identify	*Asset Management *Risk Assessment *Improvement
Protect	*Identity Management, Authentication, and Access Control *Awareness and Training *Data Security *Platform Security *Technology Infrastructure Resilience
Detect	*Continuous Monitoring *Adverse Event Analysis
Respond	*Incident Management *Incident Analysis *Incident Response, Reporting, and Communication *Incident Mitigation
Recover	*Incident Recovery Plan Execution *Incident Recovery Communication

Table 1

For most organizations, the NIST Cybersecurity Framework is best used as a starting point for implementing cyber and physical security programs and can guide an organization in determining the maturity level within each of the six functional areas.

2. Federal Energy Regulatory Commission (FERC)

The interstate transmission of electricity and natural gas is regulated by the FERC, an independent agency of the United States government. Unlike NIST's voluntary Framework, FERC's cyber and physical reliability standards are mandatory for the protection of the North American Bulk Electric System (BES). The BES, often referred to as "the grid," is the network of interconnected electrical systems consisting of power generation, transmission facilities (rated at or above 100 kV) and control systems. The facilities and control systems are necessary to maintain an uninterrupted flow of electricity to homes and businesses across the country.

In 2003, the largest power outage in the history of North America was triggered by vegetation contacting overloaded transmission lines. Widespread blackouts were experienced by 50 million customers through the northeastern United States and Ontario. In response to this preventable event, Congress expanded FERC's role and jurisdiction pertaining to the BES, as discussed below.

a. North American Electric Reliability Corporation (NERC)

In 2006, FERC designated NERC as the Electric Reliability Organization (ERO) to develop and enforce mandatory reliability standards for the electric grid. In 2008, Critical Infrastructure Protection (CIP) reliability standards were introduced to safeguard the power grid from cyber and physical attacks. These standards required identifying and protecting critical assets, implementing security controls, and conducting regular assessments to ensure compliance. FERC may impose significant penalties for non-compliance. In 2014, NERC in partnership with NIST, mapped each CIP reliability requirement to the NIST Cybersecurity Framework function, category, and subcategory.

NERC CIP standards prescribe core protections and practices for designated assets owned and operated by electric utilities. NERC further oversees enforcement of CIP standards through a cyclical compliance audit program. Compliance failures may trigger sizable penalties, of as much as one million dollars per day per violation, and are resolved under additional scrutiny by NERC and FERC.

As directed by FERC, NERC develops revisions and additions to existing CIP standards that must be approved for enactment by FERC. **Table 2** lists the current 13 NERC CIP standards, which address requirements for identifying critical cyber assets, developing security management controls, training, facility security, supply chain risk management, use of firewalls, and incident reporting and recovery. Also shown is CIP-015, which is pending FERC approval. CIP-015 will require network security monitoring within trusted zones, such as electronic security perimeters, to effectively detect intrusions and malicious activity.

NERC Critical Infrastructure Protection Reliability Standards 2024		
Standard	**Title**	**Purpose**
CIP-002	BES Cyber System Categorization	Identify and categorize BES cyber systems and their associated BES cyber assets.
CIP-003	Security Management Controls	Specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES cyber systems against compromise that could lead to misoperation or instability in the BES.
CIP-004	Personnel and Training	Require an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES cyber systems.
CIP-005	Electronic Security Perimeters	Manage electronic access to BES cyber systems by specifying a controlled electronic security perimeter in support of protecting BES cyber systems against compromise.
CIP-006	Physical Security of BES Cyber Systems	Manage physical access to BES cyber systems by specifying a physical security plan in support of protecting BES cyber systems against compromise.
CIP-007	System Security Management	Manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES cyber systems against compromise.
CIP-008	Incident Reporting and Response Planning	Mitigate the risk to the reliable operation of the BES as the result of a cybersecurity Incident by specifying incident response requirements.
CIP-009	Recovery Plans for BES Cyber Systems	Recover reliability functions performed by BES cyber systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
CIP-010	Configuration Change Management and Vulnerability Assessments	Prevent and detect unauthorized changes to BES cyber systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES cyber systems from compromise.
CIP-011	Information Protection	Prevent unauthorized access to BES cyber system information by specifying information protection requirements in support of protecting BES cyber systems against compromise.
CIP-012	Communications between Control Centers	Protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.
CIP-013	Supply Chain Risk Management	To mitigate cybersecurity risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.
CIP-014	Physical Security	Identify and protect transmission stations and transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading outages within an interconnection.
CIP-015 (Pending FERC Approval)	Internal Network Security Monitoring	Improve probability of detecting anomalous or unauthorized network activity to facilitate improved response and recovery from an attack.

Table 2

b. North American Energy Standards Board (NAESB)

NAESB is an industry forum for the development of standards to promote more competitive, efficient, and transparent business processes for the wholesale and retail natural gas and electric industries. NAESB standards development process involves support from DOE, FERC, NERC, NARUC, state utility commissions, and other governmental agencies at both the federal and state level. NAESB standards are adopted based on a consensus process and are initially voluntary; however, these become mandatory for public utilities upon approval by FERC. NAESB standards apply to four industry quadrants:

- Wholesale Gas Quadrant
- Retail Gas Quadrant
- Wholesale Electric Quadrant
- Retail Electric Quadrant

The standards within each quadrant continue to evolve to meet industry needs. For example, on September 19, 2024, FERC approved the most recent version of the business practice standards for the gas industry. The approved standards include revisions such as consolidating existing NAESB cybersecurity-related standards into a single manual. This effort should expedite the NAESB and FERC standards revision process. The standards strengthen cybersecurity protections through the use of secure communication and encryption methodologies, as well as measures to mitigate vulnerabilities such as:

- Using whitelisting and multi-factor authentication for file-to-file transactions.

- Incorporating firewalls, intrusion detection, and intrusion prevention system.

- Ensuring Open Access Same-Time Information Systems applications are secure against common industry recognized vulnerabilities.

- Applying software patches and updates in a timely fashion, ideally within seven days of availability.

- Performing quarterly vulnerability scans and penetration testing as well as annual business continuity and disaster recovery exercises.

3. Department of Homeland Security (DHS)

DHS is the federal executive agency responsible for public security. DHS has six overarching security plan initiatives, one of which is to secure cyberspace and critical infrastructure. The Homeland Security Act of 2002 gave DHS the overall responsibility to collaborate with government and private sector participants to develop the National Infrastructure Protection Plan (NIPP) to manage risk and achieve security and resilience outcomes. The initial version of the NIPP was released in 2006 and the most recent version in 2013 further integrates cyber and physical security planning.

The 2013 NIPP identifies 16 critical infrastructure sectors from all levels of government and industry, one of which is the energy sector. Other sectors, for example, include emergency services, communications, food and agriculture. The NIPP directs DHS as the lead agency to coordinate with the critical infrastructure sectors to improve information sharing and collaboratively develop and implement risk-based approaches to cyber and physical security and the resilience of critical infrastructure assets, systems, and networks.

a. Cybersecurity and Infrastructure Security Agency (CISA)

In 2018, Congress passed the Cybersecurity and Infrastructure Act, establishing CISA within DHS. Its mission is to protect the nation's critical infrastructure from cyber and physical threats, and the networks of federal civilian agencies from cyber threats. CISA works with partners across government and industry to communicate current cyber trends and attacks, manage cyber risks, strengthen defenses, and implement preventative measures.

CISA develops and publishes rules for companies that provide critical infrastructure and will require reports of cybersecurity incidents within 72 hours and ransomware attacks within 24 hours. CISA provides alerts about current security issues, vulnerabilities, and exploits. CISA's Joint Cyber Defense Collaborative is a public-private partnership that proactively gathers, analyzes, and shares actionable cyber risk information to enhance cybersecurity planning, cyber defense, and response.

CISA further administers the Cyber Safety Review Board that conducts fact-finding and produces recommendations in the wake of major cyber incidents. The Board consists of cybersecurity experts from the private sector and senior officials from government agencies such as DHS, CISA, DOD, FBI, and Office of Management and Budget.

b. Transportation and Security Administration (TSA)

TSA is an arm of DHS charged with developing key policies and securing the nation's transportation systems (e.g., pipelines, ports, highways, railroads, and mass transit systems) from all threats, including physical and cyber attacks.

Prior to the Colonial Pipeline cyber attack in 2021, TSA's Pipeline Security Guidelines relied on voluntary industry compliance. Following the attack, TSA, in coordination with CISA, issued two Security Directives mandating that critical pipeline owners and operators implement cybersecurity measures. The first Directive required pipeline owners and operators of critical pipelines to designate a cybersecurity coordinator. The coordinator is required to be available to TSA at all times to coordinate cybersecurity practices and report any incidents to CISA. The report must identify any gaps, develop a remediation plan if necessary, and report the results to TSA and CISA.

The second Security Directive required owners and operators of critical pipelines to implement specific mitigation measures to protect against ransomware attacks and other known threats to IT and ICS/OT systems. The Directive further required pipeline operators to implement a cybersecurity contingency and recovery plan, and to conduct a cybersecurity architecture design review.

In 2023, TSA updated its Security Directives to require oil and natural gas pipeline owners and operators to:

- Annually submit an updated cybersecurity assessment plan to TSA for review and approval.

- Annually report the results from the previous year's assessment, with a schedule for future assessment and auditing of specific cybersecurity measures for effectiveness. TSA requires all security measures of owners and operators to be assessed every three years.

- Develop and maintain a Cybersecurity Incident Response Plan (CIRP) that includes measures to be taken in the event of a cybersecurity incident.

- Test at least two CIRP objectives for effectiveness and include individuals serving in positions identified in the plan for their required annual exercises.

4. Department of Transportation (DOT)

While TSA's Security Directives require pipeline owners and operators to adequately prepare for and respond to cyber and physical attacks, the Pipeline and Hazardous Materials Safety Administration (PHMSA), within DOT, regulates the safe transportation of oil and gas pipelines. PHMSA oversees the safe design, operations, and maintenance of oil, gas, and other hazardous materials pipelines. This includes the oversight of pipeline control rooms and the ICS/OT side of pipeline operations.

PHMSA monitors compliance by operators of transmission and distribution pipeline systems through field inspections of facilities, operator management systems, procedures, and processes, and has a range of enforcement mechanisms and penalties for violations of its regulations. Although PHMSA does not have direct authority to regulate cyber and physical security, its safety oversight is clearly linked to security. PHMSA reviews and inspects the facilities and systems of owners and operators and enforces both safety and security-related requirements such as:

- Developing security plans that include elements such as personnel security, unauthorized access, and en-route security.

- Developing and maintaining emergency response information that includes mitigation measures to be taken when an incident occurs.

- Providing incident details to the National Response Center within one hour of discovery.

PHMSA and TSA have an interagency information-sharing agreement that enhances coordination efforts to advance pipeline safety and security, and improve information sharing on security incidents.

5. Department of Energy (DOE)

DHS designated the DOE as the lead agency to oversee energy sector security, which includes the electricity, oil, and natural gas industries. In partnership with DOE, the Electricity Sector Coordinating Council and the Oil and Natural Gas Coordinating Council developed an Energy Sector-Specific Plan (ESSP) to help achieve the following critical infrastructure security and resilience goals:

- Assessing security risks and threats
- Securing critical infrastructure from all hazards
- Enhancing critical infrastructure resilience
- Sharing information
- Promoting learning and adaptation

The approaches and activities discussed in the ESSP to support these goals are:

- Risk Management
- Interdependence and Coordination
- Information Sharing and Communication
- Critical Infrastructure Resilience and Preparedness

a. Risk Management

The energy sector faces a wide variety of risks that are evolving and may be difficult to assess or quantify due to a high level of uncertainty about the frequency or severity of events. Some of these risks include cyber and physical security threats. As such, the ESSP identified some initiatives undertaken by the energy sector to address these evolving risks.

One initiative is the DOE's development of the Energy Sector Cybersecurity Framework Implementation Guidance. The Guide is used to facilitate the energy sector's implementation of the NIST Cybersecurity Framework using existing sector-specific standards, tools, and processes to help the energy industry manage and protect its systems.

Another initiative is DOE's development, in collaboration with industry partners, of the Cybersecurity Capability Maturity Model (C2M2) to improve the energy sector's cybersecurity capabilities and to understand the cybersecurity posture of the industry. The C2M2 is a voluntary self-assessment used to evaluate, prioritize, and improve cybersecurity capabilities. C2M2 addresses new technologies such as cloud computing, mobile computing devices (e.g., smartphones and laptops), and artificial intelligence, as well as evolving threats such as ransomware and supply chain risks. It also included a secondary assessment to gauge a baseline maturity indicator level measurement for the ICS/OT environment. Two distinct C2M2s exist—one for the electric industry and another for the oil and natural gas industry.

b. Interdependence and Coordination

Technical innovations and developments in digital information and communications dramatically increased interdependencies among the nation's critical infrastructure sectors. Energy infrastructure provides essential fuel to all critical infrastructure sectors, and without energy, none of them can operate properly. Thus, its reliable operation is so critical that a disruption or loss of energy function will directly affect the security and resilience of other critical infrastructure sectors.

Both electricity and natural gas sector stakeholders in government and private sectors have undertaken a wide variety of approaches to address these concerns, including reliability assessments, interdependency studies, and coordinating activities, as well as policy reforms to enhance the coordination and scheduling of natural gas pipeline capacity with electricity markets.

To better understand and mitigate potential impacts of cross-sector interdependencies, various regional and local exercises and coordinating activities are underway, including the Regional Resiliency Assessment Program. The program evaluates critical infrastructure from an all-hazards perspective to identify dependencies, interdependencies, cascading effects, and resilience characteristics, as well as regional capabilities and gaps.

c. Information Sharing and Communication

The DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) is the lead agency responsible for monitoring and responding to disruptions to the energy sector, including cyber and physical attacks. CESER works with state and local governments to share threat and intelligence information.

Many information sharing mechanisms exist between government and industry, within the critical infrastructure community, as well as through various industry trade associations. The Homeland Security Information Network (HSIN) provides a national platform to share homeland security information with sector partners. HSIN is a secure, web-based platform for sensitive, but unclassified information sharing and communication among federal, state, local, and private entities, as well as international partners. HSIN is just one of many information sharing mechanisms for critical infrastructure.

There are three key private sector information sharing tools in the energy sector: the Electricity Information Sharing and Analysis Center (E-ISAC), the Oil and Natural Gas ISAC (ONG-ISAC), and the Downstream Natural Gas ISAC (DNG-ISAC). These three ISACs serve the same objectives: collaboration, trusted information sharing, and timely threat intelligence analysis. Industry participation in the ISACs is voluntary.

d. Critical Infrastructure Resilience and Preparedness

Incident response planning and exercise is an essential part of the energy sector's resilience because preparation minimizes the disruption of critical infrastructure functions and associated consequences during an incident. Many incident response initiatives are in place to help maintain a secure, reliable, and resilient energy infrastructure. Preparation exercises are held at the federal, regional, state, local, and private levels, and are designed to prepare for and respond to incidents in order to minimize impacts resulting from a disaster. DOE and other government partners work with their industry partners for planning and encourage them to participate in the exercises.

To test these plans and response frameworks, government and industry participate in different exercises that may be organization-specific, regionally-focused, sector-specific, national, or international in nature. For example, NERC's biennial Grid Security Exercise (GridEx) allows participants to consider scenarios that impact their operations and require them to test response, mitigation, and recovery activities.

B. State Jurisdiction

Cyber and physical security protection efforts continue to rise to meet evolving threat vectors and methods trigger changes to federal protection standards and requirements. Florida utilities must continuously reassess protections and resource allocations. Cyber threats at the distribution energy resource level have increased significantly because of the increased interconnectivity of SCADA systems and public network infrastructure. As the penetration level increases, it is imperative to employ system-monitoring techniques and for state regulators to broaden their knowledge as they regulate public utility practices and cybersecurity.

Pursuant to Chapter 366, Florida Statutes (F.S.), the FPSC regulates all intrastate operational aspects, including rates and safety, of four investor-owned electric utilities and five investor-owned natural gas utilities. Chapter 366, F.S., also gives the FPSC jurisdiction over 35 municipal and 18 rural cooperative electric utilities with regard to rate structure, territorial boundaries, bulk power supply operations, and planning. Similarly, the FPSC has limited jurisdiction with regard to territorial boundaries for 27 municipal natural gas utilities and four gas districts. In addition, Chapter 368, F.S., gives the FPSC jurisdiction over the owners and operators of intrastate gas transmission and distribution facilities regarding their compliance with the FPSC's rules and regulations governing safety standards.

Relevant sections of Chapters 366 and 368, F.S., regarding jurisdiction over planning and development, safety standards, rates, and repair of facilities are provided in **Appendix 1**.

1. Electric Jurisdiction

FPSC jurisdiction is limited to electric distribution systems and local transmission facilities below a rating of 100 kV. However, NERC's national protection CIP reliability standards, under the authority of FERC, are designed to protect the BES, those transmission facilities rated at or above 100 kV. This jurisdictional separation is significant since the large transmission facilities under FERC jurisdiction are targets of far greater value and impact to large and sophisticated cyber attackers, particularly nation-state sponsored actors. The CIP standards impose a comprehensive set of requirements designed to protect critical cyber assets and ensure reliable operation of the BES.

Though distribution and lower voltage transmission lines under FPSC jurisdiction are interconnected with the BES, attacks on distribution facilities and low-voltage transmission facilities tend to produce localized outages that are easily resolved through switching activities. However, the continuing deployment of Distributed Energy Resources (DERs) also introduces potential cybersecurity challenges for electric utilities. DERs are small, modular energy generation and storage technologies, such as small wind turbines, rooftop solar systems, and battery storage. They are connected to the distribution system and often installed on the customer side of the meter.

Chapter 25-6, Florida Administrative Code (F.A.C.), is a set of agency rules that govern service provided by electric public utilities in Florida. The chapter is divided into several parts, including: records and reports, general management safety and reporting requirements, general service provisions, inspection of facilities, and notification of significant electrical outages and events. **Appendix 2** highlights the rules of Chapter 25-6, F.A.C., relevant to protecting transmission and distribution facilities.

Florida's municipal electric utilities that are members of American Public Power Association are provided with a "playbook" to help them prepare a cyber incident response plan, prioritize their actions and engage predetermined contacts during cyber incident response, and coordinate messaging. The playbook serves three key purposes:

- Provides guidance to help develop a cyber incident response plan and outline the processes and procedures for detecting, investigating, eradicating, and recovering from a cyber incident.

- Maps out the industry and government partners that public power utilities can engage during a significant cyber incident to share information, get support for incident analysis and mitigation, and coordinate messaging for incidents that require communication with customers and the public.

- Outlines the process for requesting cyber mutual aid from utilities across the energy industry for a cyber event that significantly disrupts utility business or operational energy delivery systems and overwhelms in-house cyber resources and expertise.

Similarly, Florida electric cooperatives who are members of the National Electric Cooperative Association, have committed to use Essence, a market-ready early warning system that continuously assesses the electric grid for system anomalies. It was developed in collaboration with the DOE and is a cybersecurity tool used to protect key systems against unknown and emerging threats.

2. Natural Gas Jurisdiction

Natural gas is used by industrial, commercial, and residential customers, and fuels about 72% of Florida's electricity generation. It is transported to Florida customers through three major and two minor interstate pipelines regulated by FERC. The FPSC approves the need for certain new intrastate natural gas pipelines in Florida and is responsible for the safety of all natural gas operations within the state.

The American Gas Association is a primary source for natural gas utilities to stay abreast of federal government cyber and physical security initiative. For jurisdictional purposes, the FPSC is certified and authorized through PHMSA and Chapter 368, F.S., respectively, to physically inspect intrastate transmission and distribution pipelines. The FPSC has adopted the federal standards as well as more stringent regulations found in Chapter 25-12, F.A.C. PHMSA also authorizes the FPSC to conduct oversight and enforcement of pipeline operators through PHMSA's State Pipeline Safety Program. **Appendix 3** highlights some of the rules of Chapters 25-7 and 25-12, F.A.C., relevant to safety of gas transportation.

IV. Assessment Plan Recommendations

The Legislature tasked the FPSC, in consultation with the Division of Emergency Management and the Florida Digital Service, to develop and recommend a plan for conducting an assessment of "the security and resiliency of the state's electric grid and natural gas facilities against both physical and cyber threats." Ch. 2024-186, section 20, Laws of Fla. This Chapter sets forth the recommended areas of assessment. With any plan, the first step would be the framing of the scope of the assessment and the designation of a lead or coordinating organization under the auspices of the State of Florida to conduct the assessment. Options include state agencies, or the creation of a new entity to fulfill that role. Of particular concern will be the interaction of the assessment team with sensitive information, as discussed in **Chapter V**.

The assessment team can request each utility to describe and document how it addresses these key functions and activities, particularly how it evaluates their adequacy. This process would entail interviews of managers at many levels, and collection of documents such as risk assessments, recovery plans, internal audit reports, consultant reports, evidence of compliance with regulatory requirements, and readiness testing reports.

Within the above six functions, the Commission recommends evaluation of the utility's execution of the following activities and approaches characteristic of effective cyber and physical security programs. Evaluation of the extent to which a utility has prioritized and undertaken these activities will provide the basis for assessing its overall preparedness against attacks.

A. Risk Assessment, Monitoring, and Mitigation

Comprehensive approach to enterprise risk assessment and prioritization of responses

Utilities must take comprehensive ongoing efforts to stay abreast of both cyber and physical security risks. As in other areas of operations, the use of a risk register is necessary for identifying specific risks and tracking mitigation measures. Risk registers are also used in assessing the relative probability of negative risk outcomes, as well as their potential impacts.

Once the list of identified risks is compiled, ranking and prioritization of mitigation efforts can proceed. These decisions usually require direction and decision-making by senior managers within the organization. Regular review by senior management and the board of directors is appropriate. Due to the changing threat landscape, frequent review and revisions of the risk register are required.

Ongoing monitoring of risks and development and execution of mitigation efforts

Mitigation strategies, specific tasks, and timelines for each risk are identified in a risk register. The process of identifying and mitigating risks is a never-ending iterative process.

Mitigation tasks are broken down into subtasks, and assigned to units or individuals who can be held accountable. Ongoing feedback loops must be used to measure progress towards mitigating each risk and to keep multiple levels of management up to date. Off-target results should trigger investigation and corrective action.

During this process, an ongoing probability versus magnitude of impact evaluation may be performed for each identified risk. This process assists the entity in prioritizing and targeting resources.

B. Self-Evaluation of Processes and Internal Controls

Risk-based program of internal audit activities to assess adequacy and effectiveness of internal controls and procedures

In all organizations, internal and external audits are the primary tool for assessing internal controls. A rigorous audit program is essential to determine the adequacy of cyber and physical security internal controls.

Audits are designed and prioritized on the basis of perceived risks for all areas of operations. These audits should address a variety of security-related issues such as patch management, insider risk management, network monitoring, and physical security management at selected facilities or locations. Changes in the threat environment or within internal processes require ongoing reassessment of the adequacy of internal controls and procedures.

The high degree of subject matter expertise required to evaluate cybersecurity protections may require use of external resources and consultants. This approach adds to the layering of defense in depth. Cybersecurity consultants specialize on areas, such as threat detection, penetration testing, and surveillance, that can greatly expand the scope of capabilities for even large utilities.

Maintaining compliance with the regulatory requirements mandated by various federal agencies requires constant vigilance. Some agencies perform periodic compliance audits, issuing findings that require management response and corrective action. Extensive efforts by utilities are required to track and implement required corrective action.

Ongoing self-evaluation of rigor and development of the cyber and physical security organization

As risks posed by potential cyber and physical security attacks grow, utility protection programs must increase in strength and maturity. To gauge this development, many utilities incorporate the DOE's C2M2 program as a foundational component of their cybersecurity risk management program. C2M2 is derived from multiple cybersecurity standards and frameworks, including NIST. The program assesses the maturity level of cybersecurity processes and practices. Each maturity rating level indicates a higher degree of protection capability.

Other models include Edison Electric Institute's "Culture of Security" self-assessment tool for utilities. A utility's internal or external audits may also provide evaluation of program maturity and overall capability.

Ongoing self-evaluation of voluntary adherence to the NIST Cybersecurity Framework
The NIST Cybersecurity Framework provides voluntary guidelines for developing an effective cybersecurity program. Most large utilities perform periodic reviews comparing their programs and processes to the recommendations of the NIST framework.

C. Regulatory Compliance

Compliance with FERC-approved NERC CIP reliability standards and North American Energy Standards Board (NAESB) business practice standards.
As discussed in **Chapter III**, FERC regulations, orders, and standards prescribe actions required of jurisdictional utilities. On behalf of FERC, NERC operates its Compliance Monitoring and Enforcement process, based on periodic audits of compliance with the CIP standards. Non-compliance can result in substantial fines and follow-up monitoring of corrective action. This process also relies on electric utilities self-reporting potential non-compliance issues. While self-reporting is voluntary, the practice is viewed favorably by the regulator and demonstrates a strong company culture of compliance.

FERC also approves NAESB business practice standards and communication protocols for natural gas and electric utilities. FERC conducts audits to ensure compliance with the NAESB standards and can impose penalties for non-compliance. The standards promote more competitive, efficient, and transparent business processes for the wholesale and retail natural gas and electric industries.

Compliance with applicable rules and regulatory requirements of DHS, CISA, TSA, and DOE
Several federal agencies play keys roles in the oversight of cybersecurity and physical security protections for electric utilities. They provide resources and collaboration to assist utilities in their efforts, and also issue standards and enforce compliance requirements.

These agencies include DHS, CISA, TSA, and the DOE. Within DHS, the TSA oversees directives and rules relating to the natural gas sector through its Pipeline Security Guidelines and Security Directives.

Compliance with applicable state statutes, FPSC rules and orders, and participation in Commission's periodic operational reviews of cyber and physical security protections
Investor-owned electric utilities and natural gas distribution utilities are subject to compliance with FPSC rules and statutory requirements.

Since 2013, the FPSC has performed periodic management audits regarding Florida's investor-owned electric utilities risk mitigation measures, internal controls, CIP compliance, employee training, attack simulation exercises, and recovery planning. Though this review process requires utilities to share sensitive information, care is taken to maintain confidentiality protections afforded by applicable statutes. Written reports summarize these reviews to update the Commission and staff regarding safeguards planned and in place.

D. Information and Operational Technology System Protection

Ongoing monitoring of critical systems access authorization for utility and third-party personnel, and through password and multi-factor authentication control procedures

Many cyber attacks begin with unauthorized system access through simple methods such as phishing or errors involving access card controls. Necessary access by contractors and other third-party personnel presents a challenge. Basic controls include password protection and multi-factor authentication control procedures, the effectiveness of which depends on employees' awareness and compliance.

Ongoing monitoring of server and application network environment configuration changes, system updates and patching, and maintaining records of IT and ICS/OT system events and disruptions

Basic necessary monitoring controls for utilities of all sizes include monitoring of server and application network environment configuration changes, system updates and patching, and maintaining records of IT and ICS/OT system events and disruptions.

Coordinated protections and separation of IT and ICS/OT systems

The electric utilities manage cybersecurity risks inherent in the convergence of IT/OT networks through multiple layers of security to ensure system reliability and resilience. Converged assets are tracked by a monitoring software that logs information and part numbers to facilitate sourcing currently held hardware and software IDs. Both physical and electronic security devices are used within the converged IT/OT network which are monitored by security operations analysts.

Utilities employ firewalls, intrusion detection devices, built-in redundancies, and network segmentation to block and isolate unwanted traffic to protect against internal and external security threats.

Rigorous supply chain screening and protection controls including upstream verification of vendor sourcing through software and hardware bill of materials, and damage protection contract language

Supply chain vulnerability continues to be a major concern and protection strategies have changed rapidly in response. To protect against supply chain compromise, utilities have updated supply chain standards to reflect current requirements, added protections into its contracts with third-party vendors, and continue to work with industry partners to execute upgrades and countermeasures as they become available. FERC has issued and updated CIP-013 standards in recent years. Many utilities have added damage protection contract language that indemnifies them against losses caused by vendors.

Although not explicitly mandated in the NERC CIP supply chain standards, utilities may request software and hardware vendors to provide a bill of materials. The utility's contract language may require vendors to apply industry best practice updates to antivirus and patching technology to manage the integrity of purchases to minimize security risk.

Application of endpoint detection and response and threat-hunting tools (provided in-house or by consultants)

By employing multiple layers of network monitoring, utility cyber defense teams detect and identify anomalous cybersecurity activity. Automated IT threat detection tools are available to detect, triage, and respond to attacks. Third-party consultants are employed to perform OT monitoring that provides threat detection and mitigation. Consultants may conduct penetration tests to identify weaknesses or vulnerabilities in systems, networks, human resources, or physical assets.

E. Readiness Testing Activities

Response and recovery planning, preparation, and updating of post-incident response and recovery plans

As part of the emerging cybersecurity threat, all Florida utilities prepare and periodically review recovery and business continuity plans. These activities have gone on for years. Vigilance to ongoing updates are necessary to reflect lessons learned from cyber and physical security incidents.

After a cyber or physical security incident, Florida utilities must be prepared to notify the appropriate contacts at the Florida Department of Law Enforcement Fusion Center, Florida Division of Emergency Management, and the Commission pursuant to Rule 25-6.018, F.A.C. Additionally, lines of communication should be prepared for necessary reporting to FERC, DHS, DOE and other agencies. For example, CISA, pursuant to the Cyber Incident Reporting for Critical Infrastructure Act of 2022, will require entities across all critical infrastructure sectors to report cyber incidents to CISA within 72 hours and any paid ransom demands within 24 hours.

Utilities must rely on automated tools and processes for backup and storage of information required to recover BES cyber system functionality. An ongoing secure system backup program is critical to recovery from malware and ransomware attacks.

Large and small utilities may benefit from participation in Edison Electric Institute's Cybersecurity Mutual Assistance Program. This assists smaller companies such as electric cooperatives and municipal utilities to leverage the resources of large utilities.

Testing attack readiness through facilities inspections and simulation exercises

Many utilities participate in or monitor NERC's biennial nation-wide GridEx security exercise or perform their own drills and exercises. Mock cyber drills and exercises enhance the ability to respond to cyber and physical security threats. Drills and programs range from malware detection, tabletop exercises, to activating command and control structures. Lessons-learned from testing should be used to update recovery plans.

Utilities also conduct periodic exercises to evaluate the adequacy of emergency response plans and preparedness that focus specifically on nuclear power plants. For example, the U.S. Nuclear Regulatory Commission (NRC) and Federal Emergency Management Agency (FEMA) created a guidance document that requires nuclear power plant personnel to perform hostile action-based exercises during every eight-year planning cycle with federal, state, and local participation.

Collaboration and information sharing through industry associations, law enforcement agencies, and ISACs

Utilities share threat intelligence and risk mitigation measures through multiple government partners, vendors, industry groups, and regulatory entities to better manage and reduce security risks. The DHS's Cybersecurity and Infrastructure Security Agency provides alerts containing timely information about current security issues, vulnerabilities, and exploits.

DOE's Cybersecurity Risk Information Sharing Program (CRISP) is a public-private data sharing and analysis platform managed by NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to facilitate sharing of cybersecurity threat information among energy sector stakeholders. Through partnership with energy sector owners and operators, CRISP leverages advanced sensors and threat analysis techniques developed by DOE to better inform the energy sector of high-level cyber risks. Participation in CRISP allows utilities to share real-time threat information anonymously and to identify additional safeguards as needed. CRISP also provides utilities access to FBI advanced threat intelligence.

E-ISAC serves as the primary channel for gathering and analyzing security information from platforms such as CRISP. E-ISAC receives and coordinates incident reports and communicates mitigation strategies for energy sector stakeholders.

DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) in partnership with the National Association of Regulatory Utility Commissioners (NARUC) have established cybersecurity baselines for electric distribution systems and distributed energy resources. The partnership continues to develop implementation strategies and adoption guidelines with state regulatory agencies and industry stakeholders.

Local, state, and federal law enforcement agencies, such as local police, coast guard, and FBI, share potential security threat information. The FDLE oversees the Florida fusion centers. The exchange of information also exists through specific utility partnerships with InfraGard for seamless collaboration with the FBI Joint Terrorism Task Force and others including DHS and the Electricity Subsector Coordinating Council.

V. Analysis of Confidentiality Issues

A. Communicating, Collecting, Sharing, Storing, and Protecting Information

The Legislature tasked the Commission to develop and recommend a plan for conducting an assessment of "the security and resiliency of the state's electric grid and natural gas facilities against both physical and cyber threats." Ch. 2024-186, section 20, Laws of Fla. The Legislature specifically required the Commission to address "the manner in which information needed to conduct a security and resiliency assessment may be communicated, collected, shared, stored, and adequately protected from disclosure to avoid adverse impacts on the safe and reliable operation of the state's electric grid and natural gas facilities." *Id.* To address those issues as directed, this chapter will discuss:

- Information: What information is needed to assess physical and cyber security and resiliency;
- Protection: How security and resiliency information may be protected from statutory disclosure requirements; and
- Recommendations: Informational security considerations for a plan to assess physical and cyber security and resiliency.

1. Information: What Information is Needed to Assess Cyber and Physical Security and Resiliency

Conducting an assessment of the security and resiliency of the state's electric grid and natural gas facilities would require information such as:

- Technical Information: systems, infrastructure, architecture, capabilities, and weaknesses.
- Personnel Information: staffing levels, workgroup assignments, and security/resiliency employee depth chart.
- Operational Information: operational security plans, software update schedules, crisis management strategies.
- Incident Information: threat assessment strategies, crisis management plans, and restoration procedures.

This information would necessarily take the form of physical or digital records containing technical, logistical, and operational details related to physical and cyber security. As the Legislature has recognized, information of this nature could, if obtained by hostile actors, compromise the safety and reliability of Florida's critical energy infrastructure. *See* Ch. 2024-186, section 20. Therefore, paramount in a plan to conduct an assessment of security and resiliency is the protection of such records.

2. Protection: How Security and Resiliency Information May Be Protected From Disclosure requirements

In addition to the risk of disclosure due to physical and cyber threats, any agency or body of state or local government in Florida that conducts an assessment of the physical and cyber security and resiliency of the state's electric grid and natural gas facilities would be subject to the mandatory disclosure requirements of Florida's Public Records Law and the Government in the Sunshine Law, unless specifically exempted by the Legislature.

A. Public Records Law – Chapter 119, Florida Statutes

Florida's Public Records Law is contained in Chapter 119, F.S., which provides that any records made or received by any public agency in the course of its official business, as well as by any private entity acting on an agency's behalf, must be available for inspection by the public. *See* Section 119.07, F.S. The Commission is subject to the Public Records Law, as are all other agencies and governmental bodies created by law. Section 119.011(2), F.S.

The Public Records Law imposes on state agencies a broad requirement to disclose public records upon request by any member of the public. A public record is defined as "all documents, papers, letters, maps, books, tapes, photographs, films, sound recordings, data processing software, or other material, regardless of the physical form, characteristics, or means of transmission, made or received pursuant to law or ordinance or in connection with the transaction of official business by any agency." Section 119.011(12), F.S. The Florida Supreme Court has interpreted this definition broadly to encompass all "material(s) prepared in connection with official agency business which is intended to perpetuate, communicate, or formalize knowledge of some type." *Shevin v. Byron, Harless, Schaffer, Reid and Associates, Inc.*, 379 So. 2d 633, 640 (Fla. 1980). Public records must be maintained and stored according to the requirements of Section 119.021, F.S. All public records must be kept in the buildings in which they are usually used, a custodian of public records at that agency must keep such records safe and accessible for use, the records must be restored if they are damaged, and the agency must comply with retention schedules and disposal processes established by the Division of Library and Information Services of the Department of State. *See* Section 119.021, F.S.

The only exceptions to the disclosure requirements of the Public Records Law are those specifically created by statute. *See, e.g.*, *Wait v. Florida Power & Light Co.*, 372 So. 2d 420, 425 (Fla. 1979) (The Public Records Act "excludes any judicially created privilege of confidentiality and exempts from public disclosure only those public records that are provided by statutory law to be confidential or which are expressly exempted by general or specific law."); *Times Pub. Co., Inc. v. City of St. Petersburg*, 558 So. 2d 487, 492 (Fla. 2d DCA 1990) ("In fact, the right to access public documents is virtually unfettered, save only the statutory exemptions designed to achieve a balance between an informed public and the ability of the government to maintain secrecy in the public interest.")

In light of the broad scope and liberal construction of the Public Records Law, information needed to assess the security and resiliency of Florida's electric grid and natural gas facilities would ordinarily be subject to disclosure, unless the Legislature provides an express statutory exemption in order to avoid adverse impacts on the safe and reliable operation of critical energy infrastructure.

For example, Section 119.0725, F.S., exempts records related to cybersecurity and critical infrastructure from the disclosure requirements of the Public Records Law. The exempt information includes cybersecurity incident information reported pursuant to state law. Section 119.0725(2)(c), F.S. *See also* Section 282.318, F.S. (protecting state agency data, information, and technology that is gathered pursuant to risk assessments and other reports made by state agencies under the statute). Additionally, Section 119.0725, F.S., exempts from disclosure information relating to "critical infrastructure," which is defined as "existing and proposed information technology and operational technology systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health, or public safety." Section 119.0725(1)(b), F.S. However, this exemption may only protect records related to the *agency's* cybersecurity and critical infrastructure, and this may not be applicable to the information required for an agency to perform an assessment of the security and resiliency of utility-owned facilities and infrastructure in Florida.

Additionally, Section 119.0713(5)(a), F.S., is an exemption that applies to information held by a utility owned or operated by a unit of local government. In particular, the statute exempts from disclosure information related to the "security of the technology, processes, or practices . . . designed to protect the utility's networks, computers, programs, and data from attack, damage, or unauthorized access, which information, if disclosed, would facilitate the alteration, disclosure, or destruction of such data or information technology resources." Section 119.0713(5)(a)1., F.S. This exemption also protects "[i]nformation related to the security of existing or proposed information technology systems or industrial control technology systems" where its disclosure "would adversely impact the safe and reliable operation of the systems and the utility." Section 119.0713(5)(a)2., F.S. However, because this exemption applies only to information held by a municipally owned utility, it would likely not apply once the information passed into the possession of a third party, such as a government agency conducting an assessment of the security and resiliency of the utility's cybersecurity and critical infrastructure.

There are also existing exemptions related to certain information received by the Commission from public utilities providing electricity or gas to the public when disclosure could be detrimental to the business interests of the utility providing the information. Specifically, Section 366.093, Florida Statutes, exempts from public disclosure "proprietary confidential business information," which the statute defines as:

> [I]nformation, regardless of form or characteristics, which is owned or controlled by the person or company, is intended to be and is treated by the person or company as private in that the disclosure of the information would cause harm to the ratepayers or the person's or company's business operations, and has not been disclosed unless disclosed pursuant to a statutory provision, an order of a court or administrative body, or private agreement that provides that the information will not be released to the public.

Section 366.093(1), (3), F.S. There is an identical exemption relating to information received by the Commission from natural gas transmission companies. *See* Section 368.108, F.S. However, the statutes provide that the Commission shall apply the exemption only "upon request of the public utility or other person" and when "shown and found by the Commission to be proprietary confidential business information." *See, e.g.*, Section 366.093(1), F.S.

While some of the exemptions discussed above may apply to the kind of information required to conduct a security and resilience assessment of Florida's electricity grid and natural gas facilities, Florida courts tend to construe exemptions narrowly in furtherance of the legislative policy favoring disclosure. *See, e.g.*, *Rameses, Inc. v. Demings*, 29 So. 3d 418, 421 (Fla. 5th DCA 2010) (stating that "[i]n light of the policy favoring disclosure, the Public Records Act is construed liberally in favor of openness, and exemptions from disclosure are construed narrowly and limited to their designated purpose"). Therefore, proceeding with such an assessment without an explicit statutory exemption that specifically protects sensitive information related to security and resiliency risks could result in adverse impacts to Florida's electric grid and natural gas infrastructure due to the broad disclosure requirements of Florida's Public Records Law.

B. Sunshine Law – Chapter 286, Florida Statutes

Another manner in which sensitive information related to the security and resiliency of Florida's electricity and natural gas infrastructure could be exposed is through the meetings and discussions of the agency conducting the assessment. Florida's Government in the Sunshine Law ("the Sunshine Law") is found in Section 286.011, F.S., and requires that all meetings of any board or commission of any state or local agency be open and accessible to the public. It provides that "all meetings . . . at which official acts are to be taken are declared to be public meetings open to the public at all times, and no resolution, rule, or formal action shall be considered binding except as taken or made at such meeting." *Id.* Additionally, all such meetings must be noticed and publicly available, and information communicated by government officials must be stored and available to members of the public upon request. *Id*.

The Sunshine Law would likely require any meeting at which official action is taken by a commission or board conducting an assessment of the security and resiliency of Florida's electric grid and natural gas facilities to be open and accessible to the public, which could compromise confidentiality of sensitive security information. The Commission has a statutory exemption for hearings at which certain confidential or sensitive matters are discussed. *See, e.g.*, Section 350.01(9), F.S. If the Legislature desires to protect such information from disclosure, the commissions or boards participating in the assessment should similarly be exempted from the requirements of the Sunshine Law with respect to the meetings discussing this type of information.

3. Recommendations for Security and Resiliency Assessment Plan

In Chapter 2024-186, section 20, the Legislature requires the Commission to include in this plan certain recommendations addressing how information related to cyber and physical security of the electric grid and natural gas facilities may be protected from disclosure in order to avoid adverse impacts to safe and reliable operation. The Commission's recommendations are below:

A. Create Statutory Exemptions From Disclosure Requirements

As discussed above, existing exemptions from the statutory disclosure requirements of the Public Records Law and the Sunshine Law may not be sufficient to protect the sensitive information received from public utilities and other private entities in connection with a security and resilience assessment. Therefore, legislation may be required to ensure that such information is protected from disclosure by specific and explicit statutory exemptions.

Thus, we recommend that the Legislature consider the creation of a distinct and explicit exemption from the disclosure requirements of the Public Records Law and the Sunshine Law. This would ensure that, regardless of which agency or agencies are tasked with conducting or participating in the assessment, sufficient statutory protection is in place to maintain the confidentiality of sensitive security information. We recommend that the Legislature consider including the following elements in such an exemption:

- A rebuttable presumption of confidentiality for records received and meetings conducted in the course of the assessment that relate to cyber and physical security and resilience of the electricity grid and natural gas facilities.

- A minimum term of confidentiality, after which time the utility or entity that provided the information may petition to either continue the confidential status or return the information.

- A requirement that the agency or agencies conducting the assessment return or destroy all confidential information upon final completion of the assessment process.

An exemption that includes the elements above, as well as any other such provisions the Legislature deems appropriate or necessary, would sufficiently protect the information needed to conduct a security and resiliency assessment in order to avoid adverse impacts on the safe and reliable operation of the state's electric grid and natural gas facilities.

B. Transmission of Information to Other Governmental Entities

Due to the cooperation required among public and private entities to conduct a security and resiliency assessment of Florida's energy infrastructure, there is a concern that such cooperation could unintentionally increase the risk of disclosure. Unnecessarily multiplying the number of individuals in possession of confidential records or increasing the number of "custodian[s] of public records" for purposes of the Public Records Law could enhance the risk that such information will be discovered or disclosed. *See* Sections 119.011(5), 119.07, F.S. Additionally, the number of public employees in possession of sensitive material could be increased by the provision of the Public Records Law that requires agencies to adhere to the public record retention schedules and disposal process established by the Division of Library and Information Services of the Department of State. *See* Section 119.021, F.S. If each employee is required to retain a copy of the public record, then a longer retention schedule could result in more employees in possession of the same record. Due to the highly sensitive nature of the information at issue, we recommend that the Legislature mitigate this increased risk of disclosure in some way.

For example, the Legislature could exempt the information related to the security and resiliency assessment from the ordinary retention schedule and disposal process. The Legislature could either establish a special retention schedule and disposal process for the information related to the assessment and or allow the agency conducting the assessment to establish its own schedule. We recommend that the retention schedule and disposal process require disposal of records a certain number of days after transfer in order to limit the number of public employees in possession of sensitive information. In any case, the retention and disposal requirements applicable to the agency and information related to an assessment of the security and resiliency of the electric grid and natural gas facilities in Florida should be particularized to provide maximum informational security.

C. Establish a Special Commission or Working Group to Conduct the Security and Resiliency Assessment

Given the unique and highly sensitive nature of the information needed to conduct an assessment of the security and resilience of the state's electric grid and natural gas facilities, and in light of the adverse consequences of potential disclosure of such information, the Legislature should consider designating a lead or coordinating organization under the auspices of the State of Florida to conduct the assessment. This would allow the Legislature to craft unique requirements and exemptions that could adequately protect from disclosure the information that, in hostile hands, could compromise the safe and reliable operation of vital energy infrastructure. As the agency charged with economic regulation of public utilities, we recommend that at least one representative from the Commission participate in any assessment plan process to provide subject-matter expertise.

B. Conclusion

The Legislature has established a state policy that all state records be kept open for personal inspection and copying by any person. *See* Section 119.01(1), F.S. The Legislature also recognizes that the disclosure of information needed to conduct a security and resiliency assessment could result in adverse impacts on the safe and reliable operation of the state's electric grid and natural gas facilities. *See* Chapter 2024-186, section 20. Therefore, such an assessment must balance the two policy goals in the interest of public safety. We recommend that the Legislature ensure that any organization tasked with conducting the assessment be given clear directives and protections that will enable it to maintain the safety, reliability, and security of the state's energy infrastructure while safeguarding the public trust.

VI. Appendices

A. Appendix 1

FPSC Electric and Gas Jurisdiction Chapters 366 and 368, F.S. 2024	
Section	**Purpose/Description**
366.04(5)	Grants the FPSC "jurisdiction over the planning, development, and maintenance of a coordinated electric power grid" assuring "an adequate and reliable source of energy for operational and emergency purposes in Florida and the avoidance of further uneconomic duplication of generation, transmission, and distribution facilities."
366.04(6)	Gives the FPSC "exclusive jurisdiction to prescribe and enforce safety standards for transmission and distribution facilities of all public electric utilities, cooperatives organized under the Rural Electric Cooperative Law, and electric utilities owned and operated by municipalities…"
366.05(1)(a)	Requires the FPSC "to prescribe fair and reasonable rates and charges, classifications, standards of quality and measurements, including the ability to adopt construction standards that exceed the National Electrical Safety Code, for purposes of ensuring the reliable provision of service." The FPSC can also require "repairs, improvements, additions, replacements, and extensions to the plant and equipment of any public utility when reasonably necessary…"
366.05(8)	The FPSC may require Florida electric utilities to install or repair any necessary facility "if the commission determines that there is probable cause to believe that inadequacies exist with respect to the energy grids developed by the electric utility industry, including inadequacies in fuel diversity or fuel supply reliability…"
368.05(1)	Grants the FPSC "jurisdiction over all persons, corporations, partnerships, associations, public agencies, municipalities, or other legal entities engaged in the operation of gas transmission or distribution facilities with respect to their compliance with the rules and regulations governing safety standards..."
368.05(2)	The FPSC may require Florida gas utilities to file "periodic reports and all other data reasonably necessary to determine whether safety standards prescribed by it are being complied with; may require repairs and improvements to the gas transmission and distribution piping systems…"
368.104	Requires the FPSC "to fix and regulate rates and services of natural gas transmission companies, including, without limitation, rules and regulations for determining the classification of customers and services, for determining the applicability of rates, and for ensuring that the provision (including access to transmission) or abandonment of service by a natural gas transmission company is not unreasonably preferential, prejudicial, or unduly discriminatory…"

B. Appendix 2

FPSC Electric Jurisdiction Chapter 25-6, F.A.C. 2024	
Rule	**Purpose/Description**
25-6.018	**Records of Interruptions and Commission Notification of Threats to Bulk Power Supply Integrity or Major Interruption of Service**, … notification of certain situations, including any bulk power supply malfunction or accident which constitutes an unusual threat to the bulk power supply integrity.
25-6.0183	**Electric Utility Procedures for Generating Capacity Shortage Emergencies**, adopts the Florida Reliability Coordinating Council's Generating Capacity Shortage Plan … to address generating shortage emergencies within Florida.
25-6.0185	**Electric Utility Procedures for Long-Term Energy Emergencies**, … requires a long-term energy emergency plan to establish a systematic and effective means of anticipating, assessing, and responding to a long-term emergency caused by a fuel supply shortage.
25-6.019	**Notification of Events**, … must report to the Commission within 30 days of learning about any event involving a portion of the electrical system involving damage to the property of others in excess of $10,000, or causing significant damage in the judgement of the utility.
25-6.0343	**Municipal Electric Utility and Rural Electric Cooperative Reporting Requirements**, … reports include a description of each municipal and electric cooperative's planned facility inspections for transmission and distribution facilities including the number and percentage of transmission and distribution inspections planned and completed annually and the utility's quantity, level, and scope of vegetation management planned and completed for transmission and distribution facilities.
25-6.0345	**Safety Standards for Construction of New Transmission and Distribution Facilities**, … adopts and incorporates by reference the 2017 National Electrical Safety Code (NESC) C2-2017, as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. Each investor-owned electric utility, rural electric cooperative, and municipal electric system shall, at a minimum, comply with the standards in these provisions.
25-6.036	**Inspection of Plant**, … requires each electric utility to adopt a program of inspection for its electric plant to determine the necessity for replacement and repair.

C. Appendix 3

FPSC Gas Jurisdiction Chapters 25-7 and 25-12, F.A.C. 2024	
Rule	**Purpose/Description**
25-7.018	***Record of Interruptions,****…* requires each utility to keep a complete record of all interruptions affecting the lesser of 10 percent or 500 or more meters including cause, date, time, duration, remedy, and steps taken to prevent recurrence, … and to notify the FPSC as soon as detected and provide a report after service restoration.
25-12.005	***Codes and Standards Adopted,****…* requires operators of natural gas pipeline facilities to comply with the PHMSA standards in 49 C.F.R. Parts 191 and 192. …
25-12.007	***Commission Compliance Evaluations,****…* requires FPSC or its authorized representatives to be granted access to all installations or construction projects, … to records or data related to compliance with these rules, standards, or codes.
25-12.009	***Safety,****…* requires each operator to establish a continuing education program to enable customers and public to recognize a gas pipeline emergency for the purpose of reporting it to the operator, … and reduce hazards to employees, customers, and the public, …
25-12.020	***Construction Specifications and Inspections,****…* requires each operator to formulate comprehensive written construction specifications for all phases of design, installation, testing, repair, and inspection … to assure compliance with these rules, … to conduct field inspections, … and to have qualified inspectors to detect and correct any component that fails to meet these rules or construction specifications.
25-12.022	***Requirements for Distribution System Valves,****…* requires installing valves upstream of each regulator station for use in an emergency to stop the flow of gas, … sectionalizing valves, … identifying emergency or sectionalizing, and other critical valves designated on appropriate records, drawings, or maps used by the operator and referenced to above-ground structures so readily located, … protecting blowdown valves against tampering and mechanical damage,… and inspecting all valves necessary for safe system operation.
25-12.041	***Receiving of Gas Leak and Emergency Reports,****…* requires each operator to have an operating/maintenance plan containing procedures for receiving and promptly responding to reported gas leaks and emergencies on a 24-hour per day basis. …
25-12.042	***Investigation of Gas Leak Reports,****…* requires each operator to consider gas leaks reported by customers or the general public as emergencies requiring prompt response with the first priority of protecting life then property, …
25-12.044	***Interruption of Gas Service,****…* requires each operator, at the time gas service is turned off or when aware gas to a customer has been interrupted, to either lock the valve of the service line in the closed position or … plug it to prevent the flow of gas.
25-12.060	***General Records,****…* requires each operator to retain all tabulations, standards, drawings, or other records of incidents, procedures, or studies related to the compliance with these rules and adopted standards and codes, …
25-12.062	***Leak Reports,****…* requires records of gas leaks on the operator's system to show as a minimum: address of suspected leak, date/time reported, description of leak reported, date/time dispatched, worked, resolved, and leak location, and cause.
25-12.084	***Notice of Accidents and Outages,****…* requires each operator at the earliest time after detection of an incident involving the release of gas from a pipeline to give telephonic notice to the FPSC, … and to include impact and all other data required by this rule, … and to immediately report to the FPSC any incident that interrupts service to either 10 percent or more of its meters or 500 or more meters.

D. Appendix 4

Glossary of Terms

Attack Vector
A method used to gain unauthorized access to a system, network, or application. Attack vectors can be technical or human-based, and can target many different components of an organization's infrastructure.

Bulk Electric System (BES)
All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Critical Infrastructure
The systems and assets that are vital to the functioning of society, and whose destruction or exploitation could have serious consequences, including customer outages.

Critical Infrastructure Protection (CIP) Reliability Standards
A set of mandatory FERC cyber and physical security regulations and guidelines designed to protect the BES from cyber threats.

Cyber Attacks
Any kind of malicious activity that attempts to collect, disrupt, deny, degrade, or destroy information system resources or the information itself.

Cybersecurity Capability Maturity Model (C2M2)
A model approved by DOE available to utilities to assess protection of critical assets and infrastructure. C2M2 is used to evaluate cyber risks, measure cybersecurity program maturity, strengthen operational resilience, optimize security investments, and achieve regulatory compliance.

Federal Energy Regulatory Commission (FERC)
The federal agency with primary jurisdiction over the interstate transmission of electricity, natural gas, and oil. FERC enforces mandatory cyber and physical security reliability standards for the protection of the BES.

Industrial Control Systems (ICS)
Utility devices, controls, and processes that provide remote automated operation and electronic reporting. ICS include systems such as Supervisory Control and Data Acquisition (SCADA).

Operational Technology (OT)
OT is a broad range of hardware and software that detects or causes a change through the direct monitoring and control of devices, processes, and events in the physical environment. Examples include physical access control systems, and transportation systems.

Information Technology (IT)
Any equipment or interconnected system or subsystem of equipment that is used in the automatic acquisition, storage, manipulation, management, movement, control, display, switching, interchange, transmission, or reception of data or information by the executive agency.

Intrusions	A security event, or a combination of multiple security events, in which an intruder gains, or attempts to gain, unauthorized access to a system or system resource. Some intrusions may not be detected, leading to further undetected manipulation of systems, data capture, or denial of use.
Malware	Hardware, firmware, or software that is intentionally included or inserted in a system for a harmful purpose.
Multi-Factor Authentication	An authentication method that requires the user to provide two or more verification steps to gain access to a resource such as an application or an online account.
National Institute of Standards and Technology (NIST) Cybersecurity Framework	A voluntary set of standards and best practices available to utilities to better manage and reduce cybersecurity risks. The Framework provides a structured approach to assessing, monitoring, and remediating existing and potential threats.
Physical Attacks	A direct action targeting a utility's tangible assets, such as IT systems, equipment, or infrastructure. Physical attacks can result in unauthorized access to sensitive data, hardware, or software.
Ransomware	A malicious attack where attackers seize control of and encrypt a utility's data and demand payment to restore access.
Supervisory Control and Data Acquisition (SCADA)	A computerized system that is capable of gathering and processing data and applying operational controls over long distances. Typical uses include power transmission and distribution and pipeline systems.
Threat Group	A collection of individuals or a coordinated organization with malicious intent, working to carry out cyber attacks, exploiting vulnerabilities, seizing data, or disrupting operations.
Whitelisting	A list of entities that are authorized to be active or present on systems. Whitelisting identifies and blocks potential intruders, preventing infiltration of malware, unlicensed software, and other unauthorized software.

II. Outside Persons Who Wish to Address the Commission at Internal Affairs

Note: The records reflect that no outside persons addressed the Commission at this Internal Affairs meeting.

III. Supplemental Materials for Internal Affairs

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

IV. Transcript

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PROCEEDINGS: INTERNAL AFFAIRS

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

DATE: Thursday, December 19, 2024

TIME: Commenced: 9:30 a.m.
Concluded: 10:15 a.m.

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

**PLACE: Betty Easley Conference Center
Room 105
2524 Shumard Oak Boulevard
Gerald L. Gunter Building
Tallahassee, Florida

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P R O C E E D I N G S

CHAIRMAN LA ROSA: All right. Well, good morning, everybody. Today is December 19th. It is Friday, and this is our Internal Affairs meeting here at the Florida Public Service Commission. Excited, obviously holidays are just around the corner, so let's go ahead and jump in.

So as you all walked in, you probably heard some music. Rudolph the Red Nosed Reindeer. I know I got of a lot of funny looks, right? Like, how does that somehow relate to what we do.

MR. BAEZ: The people demand an explanation.

CHAIRMAN LA ROSA: They are going to get an explanation, right, because I thought if any song deserved one it was this one.

So Rudolph the Red Nosed Reindeer, there are many versions, but the one you heard today is a classic by Burl Ives. I didn't get involved in that part of it. That was just the suggestion.

So Vic Cordiano from APA got creative with his submission by saying Rudolph helps illustrate how the PSC helps to keep the lights on in an efficient and safe manner through all weather challenges. So I appreciate his creativity, because that's what I asked for. I said, hey, got to maybe stretch a little bit, it's the holiday season, let's get some Christmas music. So thank you, Vic, for your submissions, and I think it was well received, for sure.

So another very important item that we do here, of course, at Internal Affairs is acknowledge our Employee of the Month. This month it was Tony Nguyen.

I got to surprise Tony this morning and award him with the Employee of the Month award. There was a so-called meeting that was going on. I won't say if that was an official meeting or unofficial meeting, but it was intended for me to be able to see Tony face-to-face and offer him this award.

Tony joined the Commission in 2022, and served the Office of Auditing and Performance Analysis as a Regulatory Analyst Supervisor, oversees the financial review section.

Tony is dedicated to his work while providing a positive calming influence even under a heavy workload. In addition to training new employees in the audit process, Tony puts his shoulder to the wheel to produce high quality results. He is valued as a coworker by all of APA, and his world famous bread pudding apparently is a big hit. I've heard lots of great remarks related to that. I got some eyes that went up -- so sorry, Tony, for calling you out on that, but please join me and the APA office to congratulating Tony at this for the being the employee of month.

(Applause.)

CHAIRMAN LA ROSA: I do this typically on the day of our Internal Affairs, so really no one knows who it's going to be, so I appreciate Tony coming down in the spur of the moment. So thank you, Tony, again, congratulations on this month's employee of the month.

All right. Let's go ahead and jump in. I know we have got a lot going on today. A few reports that are in front of us, then, of course, a Special Agenda meeting and Service Hearing. So certainly a lot.

So let's go ahead and start off with the Ten-Year Site Plan that staff had made some adjustments to, and I will go ahead and recognize staff to present that to us.

MR. DAVIS: Okay. Good morning. I am Greg Davis with Commission staff in the Engineering division.

Item No. 1 is the draft review of the 2024

Ten-Year Site Plan of Florida's electric utilities. This version of the draft incorporate's the Commissioners comments from the November 19th, 2024, Internal Affairs meeting, and an updated executive summary, including a section on emerging trends.

Staff seeks the Commission's approval of the draft review of the 2024 Ten-Year Site Plan as amended.

Staff is available for any questions.

CHAIRMAN LA ROSA: Excellent. Thank you for that summary.

Commissioners, is there any discussion or thoughts on the Ten-Year Site Plan? Good or have you got a question?

COMMISSIONER FAY: No.

CHAIRMAN LA ROSA: Okay. Awesome.

So seeing no questions, I appreciate staff for making the adjustments that we discussed in the last meeting and bringing those items forward.

I will go ahead and -- I guess we are taking a vote on this, right? Looking over at staff. Okay, so taking a vote on this.

I am open for a motion.

COMMISSIONER FAY: Move that the Ten-Year Site

Plans are deemed suitable.

COMMISSIONER GRAHAM: Second.

CHAIRMAN LA ROSA: Hearing a motion and hearing a second.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Yay.

Opposed no?

(No response.)

CHAIRMAN LA ROSA: Show that the report is approved. So thank you, again.

Let's move on to the next report, which is our cyber security -- Cyber Security of Florida Electric Grid and Natural Gas Facilities. It's been required in statute by law that passed in the last session. And I will go ahead and recognize staff. And I am not sure who is taking the lead, but you are recognized.

MR. VINSON: Good morning. I am Carl Vinson with the Performance Analysis office. And our presentation is regarding a staff -- a draft staff report that was required under Chapter 2024-186, Laws of Florida, Section 20. And in the '24 session, the Legislature tasked the Commission with developing and recommending a plan under which, quote, "an assessment of the security and resiliency of the State's electric grid and natural gas facilities against," quote, "physical and cyber threats, may be conducted," close quote.

Upon Commission approval, the final report will be provided to the Governor, the President of the Senate and the Speaker of the House by January 31st, 2025.

As directed by the Legislature, staff consulted with and sought input from managers of both the Florida Division of Emergency Management and Florida Digital Services. The resulting draft report is presented for your consideration, and staff members are available to answer questions.

CHAIRMAN LA ROSA: Commissioners, are there any questions or thoughts regarding this report?

Commissioner Fay, you are recognized.

COMMISSIONER FAY: Thank you, Mr. Chairman.

And, you know, I have a lot of thoughts on the report and the topic. I thought this was done well. Obviously, it's a legislative mandate, and the turnaround was pretty fast. So I think the Commission did a pretty good job to get it out.

With that said, I think, you know, commissions all over the country are, like, we have this challenge of what's brought forward in rate cases or petitions, and then what process is put in place to make decisions on those. And this gets a little bit into the difficulties of what that entails.

So it seems like, based on what the Legislature wanted, we start with this assessment, but then we will -- the Commission, and likely the industry, will move forward with trying to make the best decisions as to what is maybe necessary for them to stay protected at a level that we expect with them.

My concern is that to do that in a way that is both transparent and protects national security is extremely difficult, if not, to a large degree, impossible to do both of those in a way that doesn't put our own systems at jeopardy. So I know, from our perspective, from Florida's perspective, it's been no news is good news. But the threat, as pointed out here, is real. And it's not just, you know, nation states, there is threats coming from everywhere to our utilities. And I think that we will probably see in the next 10 to 20 years, this will continue to be maybe, if not the most, but one of the most critical investments or decisions that utilities are going to have to make. So I think when we go forward with this, there is just going to have to be an assessment of how maybe staff could look at this information in a way that's protected.

I know, Carl, you have an audit process in place that you work with our utilities. Thankfully we have you at the Commission to do that, because I know it's taken a long time to build that. Thankfully we have utilities that understand that process and allow you to do that, but that's not the case in every state.

And so we don't want to lose that. We don't want to go backwards. But we also need some method to be able to look at things but recognize, as an agency, you know, specifically as a state agency, we can't -- you know, we work hard enough to guarantee to the confidentiality of proprietary information that comes forward on our dockets. There is no way that we can safely say that we should be holding any information related to the national security of our country, our state and our utilities.

So I think that's going to be really, really hard to do. And I am hopeful that, like, this is a start obviously, and it states that we are going to have some problems in doing that. But I still think we should continue doing what we are doing, even if it's deemed maybe above and beyond what the minimum standards are for cyber. So the more we look at it, I just hope that we will find a way to do that.

Carl, I know you work with people all over the country. You talk with experts on a national level. Maybe it's hiring a third party to come in and do is that with the utility, where they don't have the mandates of public records requirements that could expose the security components. I think New York does something like that.

It might be a process where they are able to come, look at it, make some assessment, and then a recommendation is provided, and that recommendation does not put in jeopardy our grid.

So I say all that I guess to say that this is a great start. I did want to get your thoughts if you see this going forward, what's put here going forward as being the next step, A, an actual assessment taking place statewide with our utilities, if it's something legislatively that would potentially come. I want to get your thoughts on maybe what we are looking at next after this.

MR. HINTON: Yeah. The bill required us to recommend a plan, and that's what we put together here, is a plan for assessment, the subject matters. But we are not advocating that this, you know, the next step, we are not -- there is no expectation what the next step will be. It's more putting it back in the hands of the Legislature. They have asked for a plan. That, we produced. And, you know, Carl, his group, I am assuming are going to continue to do the work they have been doing.

But as far as this plan that we are sending over -- sending downtown, we are just -- it's kind of back in the Legislature's court to decide if they want to pull the trigger, assign an agency, bring in a third party, that type of thing. We are just trying to kind of lay out the possibilities that they can approach it with.

COMMISSIONER FAY: Gotcha. Okay.

And to your point, it might sort of be punted back. I know Emergency Management works on, like, an incident like this occurs, sometimes we have Emergency Management activated where there is 12 obviously, but there is all of these other entities that are responsive. When you spoke to Emergency Management to work on this, and kind of put this together, did they -- did ESF-20 actually weigh in, or did you speak with anybody individually with ESF-20, or was it more just people been Emergency Management?

MR. HINTON: We didn't -- not -- we didn't speak with them in the context of ESF-20. We had people from DEM participate with us. We met with them back in July initially for a -- on a Zoom call to just talk about the project and our thoughts on it; provided an outline to them a couple weeks later in how we are planning on proceeding. And then once we worked through the draft, gave them the draft and got comments from them on what we could include, and -- but that's been the extent of it at this point.

COMMISSIONER FAY: Good. So they did give you pretty good feedback, I guess --

MR. HINTON: Yes.

COMMISSIONER FAY: -- when you provided it.

It seems like -- this is just my sort of initial research. It seems like there aren't, ESF-20 is rare. There don't seem to be a lot of states that have set up a specific cyber security division to be responsive. And so it seems like that, on the action side, I think people will look to us if something were to occur in the state that created outages. But I think the reality of it is the response -- an incident response doesn't sit within this agency. It sits within other agencies to be responsive.

And I know that can seem a bit convoluted since we have, on the front end, this assessment process, and we coordinate with the utilities. But I think that's sometimes misconstrued, that we would be the entity to do that. So it sounds like they would be the ones to be responsive if something occurred, and then, to your point, on the legislative side, if there was something that needed to be changed, or maybe the assessment needed to go to the next level and look at what a structural plan would actually look like, or the implementation of it, then we would probably be part of that. But I am not even sure we would be the lead based on what the incidents look like, or what the historical context was. And of course, we are limited on the confidentiality stuff too.

Well, I appreciate it. You guys did a great job on this. Once again, I know Carl has lived this stuff for years, and unfortunately it's not going anywhere, so you need to be at the right -- not just Florida, but to every state in their critical infrastructure. And I am hopeful that we can keep doing what we have done in the past, but I am worried, as we see this high risk coming forward, that we are going to see things in the future that will impact our grid in a way that is probably going to require large scale investments. And those will just be tough decisions down the road, and how commissions look at them will probably be tough decisions.

With that, Mr. Chairman, unless there is any other comments, I am happy to --

CHAIRMAN LA ROSA: No, I have got some thoughts --

COMMISSIONER FAY: Go ahead.

CHAIRMAN LA ROSA: -- on -- because you are asking good -- certainly a good line of questions.

And I have been on the other side of trying to understand something. And our state government is very efficient, and sometimes it does fall in the hands of other agencies. It can be difficult to try to pinpoint where does something maybe newer and emerging, and I would say the popularity and the concern of cyber security, and that's kind of where the populated concern of cyber security is emerging as technology and other threats occur, but where does that ultimately fall?

I know the Legislature asked us -- you know, I think that's where you are questions came from as far as coordinating with Emergency Management. They also asked us to coordinate with the Florida Digital Service.

Can you just opine a little bit on the interaction with Florida Digital Service, and how that interaction worked, and if there was contributions, and so forth, and what we were able to learn from that?

MR. HINTON: Very similar. They were at -- attended the same meeting where we initially kicked things off. They reviewed that outline at the same time, and they received the draft at the same time. They didn't have any input for the draft.

You know, limited -- they don't really cross over into the realm of the electric grid --

CHAIRMAN LA ROSA: Sure. Of course.

MR. HINTON: -- and natural gas facilities, so they had limited input --

CHAIRMAN LA ROSA: Right.

MR. HINTON: -- in this particular topic.

CHAIRMAN LA ROSA: Sure. Sure. Understood. And, of course, as this expands, that's kind of where it gets a little bit gray.

All right. Similar thought to where I believe Commissioner Fay was going, because I was -- when I read this, I had to go back to the statute and say, all right, let me refresh my memory. What were the discussions points, and so forth, and understand what type of report was this -- what should I get out of this report.

And I think -- we had a robust briefing, so thank you for all the staff with going through things, and I know I was asking some kind of hairbrained questions because I was just really trying to get to the bottom of things to best understand, is that I wanted to make sure that as I read through more importantly -- most importantly maybe, from my perspective, the executive summary is that where does this fall? So, like, what is -- where do we conclude?

And I -- my thought process, and Commissioner Fay, correct me if I am wrong, was that are there next steps? Do we -- were we supposed to recommend next steps? Because that's typically what a report does. And if I didn't read the statute, maybe I didn't understand that necessarily.

So is that something worthy of improving in an executive summary, not necessarily a, hey, we don't suggest next steps, but maybe opine a little bit on what -- how we consider next steps, and maybe not telling the Legislature what to necessarily do, but that, hey, this is not intended for a next step report. Correct me if I'm wrong. I should allow you to explain that.

MR. HINTON: As far as next step, you know, in the chapter where we really introduce the plan and the recommended plan in the areas of assessment that were recommended that they look at, you know, we tried to point out that, you know, the first thing you have to do when you are going to do an assessment is identify the scope of your assessment, and then identify a lead agency to take the point in running that assessment. And so that -- you know, that's kind of the -- that's -- we are presenting that as the next step --

CHAIRMAN LA ROSA: Sure.

MR. HINTON: -- of, you know, if they decide to move forward with this assessment, that that would be the first thing that they would need to do.

CHAIRMAN LA ROSA: Okay. And is that -- I don't feel necessarily that that was well-defined in the executive summary. Can that be brought into the executive summary? And Commissioners, correct me if I am wrong with my thought process on this.

COMMISSIONER FAY: I will just weigh in, Mr. Chairman.

I mean, I think -- I think even as this moved through the Legislature, some of the language adapted as to what this would look like, and see I think, to your point, Mr. Chairman, it's -- the directive, I think, we have accomplished, but I am not sure the result is real -- is clear what that looks like.

And that's the only reason I was kind of hesitant to go further, in that I think this report will, of course, go to the Legislature and the Governor's Office, who is very involved in this topic, and so I think they will have to make these decisions as to what to do with it.

And I think some states would look at something like this and determine there should be legislative mandates for certain things to be met, and the implementation of those would arguably be better for the state moving forward. And there is others that would probably go the other way and say, look, you have got FERC. NERC has these substandards we have looked at. We have these NIST industry standards. We have basically all -- I mean, you guys did a great diagram to show you have got all of these requirements and suggestions already out there on a federal level. The buck power system, I think, is what the big fear is.

I mean, of course we are Florida specific. We care if our citizens and our residents lose power. I mean, that's at the top of my mind every day that we show up here. And so I think that's a priority. But I just don't know that what the legislative -- the statutory language gave us directed us to go beyond kind of what was provided and give them directive, that next directive. And I am sure that's probably how they wanted it to be able to make a determination of what's occurring.

We have got an administration change that's happening in DC, what they will decide to do related to FERC and NERC, and those decisions, will probably have a big impact on what we decide, we, you know, as a state would want to do.

But I do want to give Carl his love. I mean, I think what he does is very hard, and I know we have all read the audits and the reports that they put out. It's a super difficult dance to do the review and not put anything that would put our grid at risk into a report, and so I -- yeah, I think that's going to be just a huge challenge going forward.

And if there is going to be open discussions about it, you know, I just -- I don't see how we, as a commission, do that. It seems much better driven by Carl or a third party, or maybe, you know, a third party consultant or something that could come in and do it and then provide us, you know, a report.

But I don't see this directive including any sort of, to your point, legislative mandates, or I even policy mandates really going forward, just to get a better idea of what it would entail to bring everything in, and then to put it in writing I think is just really to do.

CHAIRMAN LA ROSA: Yeah. And I don't disagree with you at all. I will maybe narrow my thought process in the sense of my takeaway is not necessarily substance. I think the substance is phenomenal. We had that discussion yesterday, laying out how the federal agencies maybe overlap a little bit, but have a true coverall of major infrastructure, which, from an education perspective, was an education to me for sure, because I learned and understood that and always will.

I am concerned from a Florida perspective, and I think that picture was clear, but I guess my takeaway was that, do we understand -- like, if I read this report, should I be looking for a finding? And I think we have all followed, of course, the legislative process and, of course, many times the public service name is thrown around a little, we can, and we want to understand what they are asking us to do and following as those discussions continue in the legislative process.

But that kind of goes away in the sense of I read this report next year, I didn't -- I may have followed it, but others may have not followed what was going on in the legislative process, and don't have a history of that because it's just not written anywhere, right, in the sense of, hey, I had to be paying attention to it.

So I guess what I am trying to narrow in on and saying, as I read the executive summary, do I clearly under -- I don't believe I do clearly understand that we are not making a recommendation, to Commissioner Fay's point, I don't think we -- I have all the same concerns. I don't want to include certain things because I think that there could be some security, you know, risks involved.

But I want to make sure that the reader understands that, hey, this is now intended, if I am a legislator, to make a decision, or intended for someone else, say, okay, you know, it's useful. It's -- but I -- I should not have expected the PSC to tell me exactly what to do. And that's what I get concerned every time I read the report to say, okay, great, this report was done, what is the end product? And the end product wasn't intended to say -- to pinpoint certain things. The end product was to say, hey, here's the information, here's how it's laid out, and then that's it. I don't know that I get that.

MR. HINTON: Yeah.

CHAIRMAN LA ROSA: And I talk -- I am a little long-winded it in that description.

MR. HINTON: Yeah. When we started planning for this report in reading the statute, or the bill, we didn't read it as asking us to recommend a next step --

CHAIRMAN LA ROSA: Right.

MR. HINTON: -- but just to recommend a plan for assessing.

CHAIRMAN LA ROSA: Right.

MR. HINTON: We can make it clear -- you know, we can probably easily make it clear in the executive summary by just adding a sentence, something along the lines of if the Legislature decides to do this, then -- so just making it a little bit clearer with just that one statement that it's back in their court, that we are not recommending the next step, but if you decide to move forward, then these are things you need to consider.

CHAIRMAN LA ROSA: And that's what I am looking for, is that, okay, as a reader, read the executive summary, now I have got the right mindset moving forward, I know what to expect in the next 30 to 40 pages of the report.

MR. HINTON: Yeah. We can easily clarify that to make it clear that it is -- we are just providing this for them to make a decision moving forward.

COMMISSIONER FAY: Yeah, I mean, Mr. Chairman, so that in the -- I am on page two, but the process recommendations that they include in there, where they have these bullets, I mean, it sounds -- and I don't mean to put words in your mouth, so feel free to correct me, but it sounds like when you look at this commission that the Commissioners urge the following initial steps will be required. It almost sounds like we are saying, you know, we would like you to consider. So there is not this directive that they have got to basically go this route.

And these bullets are, to a certain degree, somewhat -- they create new questions, and so maybe -- yeah, maybe being required was designed to make sure that these were thought of before an actual assessment plan is completed.

But I think, to your point, I mean, Cayce just worked on -- you guys just worked on the relay service stuff we have been working on, where the statute clearly says, we want -- the Legislature wants direction on changes that would make this run better, and so we are responsive. To the Chair's point, we don't have that and this report. We just have, you know, look at the following things and give us what we would be considering to move forward with a plan.

So with that, Mr. Chairman, does that get a little bit more of what you are saying, if we kind of soften the -- we remove sort of the necessity of those bullets to be included, and just basically said, like, here are some things that --

CHAIRMAN LA ROSA: I think -- okay, we have gone down the direction of a general approach rather than a requirement --

COMMISSIONER FAY: Yeah.

CHAIRMAN LA ROSA: -- meets that, and I will kind of look to staff, if you feel that that interferes with how you have laid this out in the rest of that section being --

MR. HINTON: I am not sure I understand. Are you talking about instead of saying, initial steps will be required --

COMMISSIONER FAY: Yeah.

MR. HINTON: -- changing that to soften it?

COMMISSIONER FAY: Correct. Yeah, because then basically, to that point, if it's an agency or the Legislature, there is sort of this clear directive of what would be included in that next step. And I think we are -- we are providing information about, you know, what would likely be

-- I don't want to use the word necessary. What would likely be material to that assessment.

And we are not saying, like, these are the only things, or this is how it has to be done. We are just basically saying that, based on your assessment working with these other agencies, that consideration of these things, I think, would be valuable to giving that full assessment.

Because the only thing I thought, when I read this, that would really be necessary, which is actually on the last line of that same section, was instead of saying, the use of outside subject matter expertise may be advisable, I feel like if it's us, it's necessary. We don't have the in-house ability to take that next step unless we go out and hire some entity that does this type of work, maybe even, you know, former military that has clearance, like individuals who are able to have us take that next step.

The reason I am not -- I don't have a lot of heartburn about that one because I think the conclusion doesn't suggest that it's -- that we are the only option. I think it could be really any -- I think the Legislature can make it clear on their own where they want the state to go, where they want utilities to go, where they want them to invest; or I think they could say, we want DEM and, you know, the folks who are involved in ESF-20, they can sort of create a structure that then looks at that and provides that actual, you know, full blown assessment, which is what you are laying out here. These are the things you consider when you do it.

MR. VINSON: I think that that's something that we had in mind, was to help them understand the magnitude of what they appeared to be -- and, again, as was mentioned, they were a little bit vague in the -- and probably on purpose -- the magnitude from the monitoring that we have been doing for 11 years to the full blown technical down in the weeds assessment of these things.

And you mentioned a third party that -- the consultant. This is what the utilities do, okay. They have run a utility and, you know, information technology for it forever. And when they get faced with this challenge, they turn to consultants.

I think you are exactly correct, very humble about what we are able to do. We are monitoring it well, but we do not have the resources on our staff. And I think it would take a combing of everybody's abilities, and the experience may not exist anywhere in our state agencies. And so there are consulting firms out there that FPLs, Dukes and TECOs are relying on, and they -- we wouldn't be that different, I wouldn't think, if we wanted to assess everything across the entirety gas industry in Florida, the entire electric industry in Florida, the massive undertaking, I can't guess how many millions of dollars of consulting work would need to be done.

COMMISSIONER FAY: And we would have the distinction of not being -- of the public records component, right? To your point, the utility can work with a third party entity and that's protected. There is some protections that we have in the statute for safety, but I mean -- we don't have to --

MR. HETRICK: We don't need to --

COMMISSIONER FAY: -- the language isn't in here, or whatever, so we don't have to get into that, but, I mean, I think --

MR. BAEZ: That's sort of an open question.

COMMISSIONER FAY: Yeah. Yeah. It's probably a distinction that's relevant that makes obviously easier to do if you don't have of that concern, and what you bring in-house, because I think we talked a lot about the public records exemption side of it.

When we -- when I was in the Attorney General's Office, we worked on data breach stuff, and so we got information from companies all the time. We don't -- on the IT side, we don't invest in that level of security that you would if you have those types of, you know, information assets. And so I don't see how we can safely say we can take in information like that, even if the public records exempt was exempted that we could safely say that we can provide these layers of protection that the private sector is providing, like, unless you feel that there are states that are doing that, I don't think we can.

MR. VINSON: Different legislatures around the country have been, you know, engaged in promulgating statutes that handle problems -- this problem, and it's specific to cyber security. So I assume the Florida Legislature is aware of what their colleagues in other states have done.

But I do believe that the utilities already working with these consultants that might be the ones that the state would turn to already have arrangements and agreements with them. It wouldn't necessarily have to do it with the same statutes that we have to comply with --

COMMISSIONER FAY: Sure.

MR. VINSON: -- but we have been working around it through the method of not taking possession of documents the entire time we have been doing our monitoring audits. And that's the extreme step we have had to take. It has not handicapped our efforts or our ability to report back on, you know, the status of and the efforts being undertaken by the utilities, but that's what we have had to do.

So I don't know if they have envisioned any of that problem. We wanted to bring it out very clearly that it's a major challenge to overcome, the confidentiality issue.

COMMISSIONER FAY: Yeah. I am glad you included it. I think it's -- yeah. And we have such broad public records, you know, which that transparency is great, but when it comes to this stuff, it just makes it really difficult.

MR. HINTON: Can I make a recommendation that -- or a proposal that might address both of the thoughts that you guys have brought up on -- going back to that sentence on page two. If we were to modify that, under B, process recommendations, that first sentence: In preparing an assessment plan, the Commission observes that the following initial steps would be advisable if the Legislature decides to require the actual assessment be implemented.

COMMISSIONER FAY: Yeah, I think it's great.

MR. HINTON: It softens that part, but also throws in that, yes, we're -- it's up to you now to require something.

CHAIRMAN LA ROSA: Yeah, I think I turn the corner with it if I read it -- if I read that right.

MR. HINTON: Okay.

COMMISSIONER FAY: Because then they can include it -- like, if the Legislature decides they want to do something, then, you know, it's not a mandate like it is with other statutes that we have seen. It's not a directive. Yeah. I never really liked telling my boss what to do, you know, that's a little more open-ended for them to decide.

CHAIRMAN LA ROSA: Right. Yeah. And that was the recommendation to cover both?

MR. HINTON: Yeah, I thought that might address both concerns.

CHAIRMAN LA ROSA: Okay. Excellent.

Commissioners, any additional further questions or thoughts?

So I am going to go back to Commissioner Fay. You were about to initiate.

COMMISSIONER FAY: Yeah, for our procedure on this, we just move to accept the report, and we will send it to the Legislature and the Governor, correct? So, yeah, so I move to approve the report.

CHAIRMAN LA ROSA: With that adjustment?

COMMISSIONER FAY: Correct, with the language as proposed, yeah. And I don't -- I don't think we need to give administrative authority, but let's just do it anyways.

CHAIRMAN LA ROSA: -- or something.

MR. HINTON: There is always a typo somewhere.

CHAIRMAN LA ROSA: Okay. So hearing a motion, is there a second?

COMMISSIONER PASSIDOMO SMITH: Second.

CHAIRMAN LA ROSA: All right. Hearing a motion and hearing a second.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Yay.

Opposed no?
(No response.)
CHAIRMAN LA ROSA: Show that the report will move forward.
Thank you all. Thank you guys for the discussion. That was very much appreciated.
All right. Let's move to our legislative update. We will recognize Mr. Frank when he is ready.
MR. FRANK: Good morning, Commissioners.
CHAIRMAN LA ROSA: Good morning.
MR. FRANK: All right. I actually have a few updates to share with you.
Organization session was held in November. We now have new leadership in the House and Senate. Senator -- Senate leadership includes President Ben Albritton, President Pro Jason Brodeur, Majority Leader Jim Boyd, and Minority Leader Jason Pizzo.
House leadership includes Speaker Daniel Perez, Speaker Pro Tempore Wyman Duggan, Majority Leader Tyler Sirois, and Minority Leader Fentrice Driskell.
Earlier this month, both the House and Senate concluded their introductory committee weeks, which primarily focused on new member education. Looking

ahead, there will be two committee weeks in January, then three more in February.

The 2025 legislative session will officially begin on March 4th and end on May 2nd. And I just want to highlight a few of the committees we will be working with.

On the Senate side, we have Senate Appropriations Committee, which will be chaired by Senator Ed Hooper. Senate Appropriations Committee on Agriculture, Environment and General Government will chaired by Senator Jason Brodeur. Senate Regulated Industries Committee will be chaired by Senator Jennifer Bradley.

And then for the House, House Budget Committee will be chaired by Representative Lawrence McClure. House State Administration Budget Subcommittee will be chaired by Representative Vicki Lopez. Information Technology Budget and Policy Subcommittee, this is a new subcommittee that will recommend the IT budget for each agency to the Budget Committee and provide legislative oversight regarding agency implementation of the IT budget. That will be chaired by Representative John Snyder. House Commerce Committee will be chaired by Representative James Buchanan.

And one notable change from the last session is that the Energy Communications and Cyber Security Subcommittee has been restructured. We now have the Economic Infrastructure Subcommittee, which considers matters related to transportation infrastructure, energy, utilities, telecommunications services, broadband services, telephone solicitation and new and unique marketplaces.

CHAIRMAN LA ROSA: That still falls under the commerce silo?

MR. FRANK: Yes. Yes. This subcommittee will be chaired by Representative Michael Caruso.

Of course, I will be tracking those of interest throughout the session and updating you on any legislative developments.

One bill we are expecting to be filed soon is legislation to modernize the Telecommunications Access System Act, or TASA. Commission staff has worked closely with FTRI on legislation that aligns with the Commission's recommendations found in the 2024 Relay Report.

This recommendation included authorizing FTRI to acquire equipment that uses technologies beyond basic landline telecommunication services and broadening the eligibility of membership on the TASA Advisory Committee.

As you know, TASA does not support equipment that uses wireless or broadband technologies. The proposed legislation incorporates definitions for technologies not existing or common at the time of the passage of the original act. The revisions will ensure FTRI has the authority to provide modern and more updated equipment.

I will keep you informed as this legislation develops and any other proposed legislation that may impact the Commission.

I will also continue to provide important update to your advisors during our weekly meetings. And that concludes my update. I am happy to answer any questions.

Thank you.

CHAIRMAN LA ROSA: Commissioners, any questions or thoughts?

This seems to be a busy time of the year for you.

MR. FRANK: Right.

CHAIRMAN LA ROSA: All right.

COMMISSIONER FAY: Didn't you used to chair the Commerce Committee?

CHAIRMAN LA ROSA: I did.

COMMISSIONER FAY: They just keep expanding that.

CHAIRMAN LA ROSA: Yeah, man. A lot of things going on in the state, man. People moving in every day, and, you know, more business activities and lots to handle in Commerce.

Awesome. Well, thank you very much for your report and look forward as the weeks come for session, you keep giving us updates. Thank you.

MR. FRANK: Thank you.

CHAIRMAN LA ROSA: Let's move to our General Counsel's report.

MR. HETRICK: Thank you, Mr. Chairman. I have not report this morning, but we are pretty busy.

CHAIRMAN LA ROSA: Awesome. Awesome. Well, thank you. I know last week, Mr. Rubottom, who was here earlier opining on the report did a great job of representing the agency in front of the Supreme Court. So thank you, Jon, for doing a great job -- are you still out there? There you are. So thank you for your hard work on that.

Let's move over to our Executive Director.

MR. BAEZ: Thank you, Mr. Chairman.

Nothing -- no -- nothing official to roll out, but your mention of the oral argument is a great segue of what a busy year we have had, and this being the last Internal Affairs, to just take a moment to consider the tail of the tape, as I call it, over this past year.

We -- naturally, we remember a couple of major rate cases that came through the door. Not unusual, but burdensome just the same. The hurricane season put a different -- you know, sprinkled some interesting magic over even those processes that were going on.

And I just want to take a moment to thank the efforts of our staff. It was all-hands-on-deck pretty much the entire year, since the beginning, and it was an extraordinary effort that everyone put out. It was an extraordinary effort that the Commission put out, having to travel for service hearings, and whatnot, and also have to be engaged during, as I said, a busy storm season, along with the rate cases.

So a lot of very tall stack of transcript, and official filings, and everything else that we all collectively had to put together. And I think -- I know I am very proud of the staff. I hope you are too.

And with that, I will close and wish everyone a Happy Holiday. Safe travels for those of you that are hitting the highways and byways, including yours truly, and enjoy time with family and friends.

Thanks.

CHAIRMAN LA ROSA: Excellent.

Well, thank you. And I appreciate you laying that out. It has been a busy year. And this time of the year, it's easy to look back, and you think of some of the events that happened and say, wait, did that happen this year? And I think this year is no exception to that.

It's certainly been a very busy year, and I am very appreciative of all of staff's efforts and, you know, we just -- you know, it's easy to plan. And I know we look at our schedules years in advance and think that we can predict what's going to happen in the future, but then sometimes Mother Nature might throw us a few curveballs, and we have done very well to be able to adjust do that, and really been on our toes and been able to pivot as necessary.

So I congratulate our staff on a year and a job well done. I am very proud of all the contributors to our agency. And you heard me say many times, I am delighted to be able to chair this commission and be a part of leading this agency, and it's good to be in a happy place, so I am thankful. I hope that everyone does have a great holiday season and a little bit of time that we have off, and we are very thankful to the Governor for those extra few days. It's well deserved, and certainly in this agency for sure.

So thank you all, and have a great year. I know that we will probably hit the ground running in January, because there is already a few things lined up, but the time is certainly well deserved. So thank you all for a great year.

Commissioners, any further matters before us? Nothing just popping out of your head that you wants to discuss?

COMMISSIONER FAY: We will see you in, like, 10 minutes.

CHAIRMAN LA ROSA: Yeah, maybe 15 minutes. 15 minutes. So let's say -- that's a good segue. So let's say it's, at 10:30, let's go ahead and meet for Special Agenda in the hearing room.

If nothing else before us, let's go ahead and adjourn this meeting.

Thank you all.

(Proceedings concluded.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 8th day of January, 2025.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028