Review Of The
2013 Ten-Year Site Plans
For Florida's Electric Utilities

Florida Public Service Commission

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List of Ten-Year Site Plan Utilities

Investor-Owned Electric Utilities

FPL	Florida Power & Light Company
DEF	Duke Energy Florida, Inc. (formerly Progress Energy Florida, Inc.)
TECO	Tampa Electric Company
GPC	Gulf Power Company

Municipal Electric Utilities & Rural Electric Cooperatives

FMPA	Florida Municipal Power Agency
GRU	Gainesville Regional Utilities
JEA	JEA (formerly Jacksonville Electric Authority)
LAK	Lakeland Electric
OUC	Orlando Utilities Commission
SEC	Seminole Electric Cooperative
TAL	City of Tallahassee Utilities

List of Acronyms

AB	Agricultural Byproducts (Biomass)
CC	Combined Cycle
CR3	Crystal River Unit 3 (Nuclear)
CT	Combustion Turbine
DACS	Department of Agriculture and Consumer Services
DEP	Department of Environmental Protection
DR	Demand Response
DSM	Demand-Side Management
EIA	Energy Information Administration
EPA	Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FEECA	Florida Energy Efficiency & Conservation Act
FRCC	Florida Reliability Coordinating Council
GWh	Gigawatt-hour
IC	Internal Combustion Generator
IGCC	Integrated Gasification Combined Cycle
IL	Interruptible Load
IOU	Investor-Owned Utility
LM	Load Management
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatt
NEL	Net Energy for Load
NUC	Nuclear Generation
NUG	Non-Utility Generator
OBS	Other Biomass Solids (Biomass)
PPSA	Power Plant Siting Act
QF	Qualifying Facilities
RPS	Renewable Portfolio Standard
SACE	Southern Alliance for Clean Energy
ST	Steam Generator
TLSA	Transmission Line Siting Act
TYSP	Ten-Year Site Plan
WDS	Wood Waste Solids (Biomass)

Executive Summary

Pursuant to Section 186.801(1), Florida Statutes (F.S.), each generating electric utility must submit to the Florida Public Service Commission (Commission) a Ten-Year Site Plan (TYSP or Plan) which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a ten-year planning horizon. The TYSPs of Florida's electric utilities are designed to give state, regional, and local agencies advance notice of 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 study of the 2013 TYSPs for Florida's electric utilities, filed by eleven reporting utilities.[1]

All findings of the Commission are made available to the Department of Environmental Protection (DEP) for its consideration at any subsequent electrical power plant site certification proceedings pursuant to the Power Plant Siting Act (PPSA).[2] In addition, this document is forwarded to the Department of Agriculture and Consumer Services (DACS) pursuant to Section 377.703(2)(e), F.S., which requires the Commission to provide a report on electricity and natural gas forecasts. A copy of this report is also posted on the Commission's website and is available to the public.

Review of the Ten-Year Site Plans

Load & Demand Forecasting

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's need for electricity. Consequently, educating consumers to make smart energy choices is particularly important.

Florida's utilities can efficiently serve their customers by offering demand-side management (DSM) and conservation programs designed to use fewer resources at lower cost. Under the Florida Energy Efficiency and Conservation Act (FEECA), the Commission is required to establish annual numeric goals for seasonal peak demand and annual energy consumption reductions.[3] The Commission has already begun the next goal-setting proceeding, which will be completed by the end of 2014.

Florida's utilities project considerable demand and energy savings over the planning period, with conservation and load management programs by 2022 reducing the system's total summer peak demand by over 9,200 megawatts (MW), and annual energy consumption by over

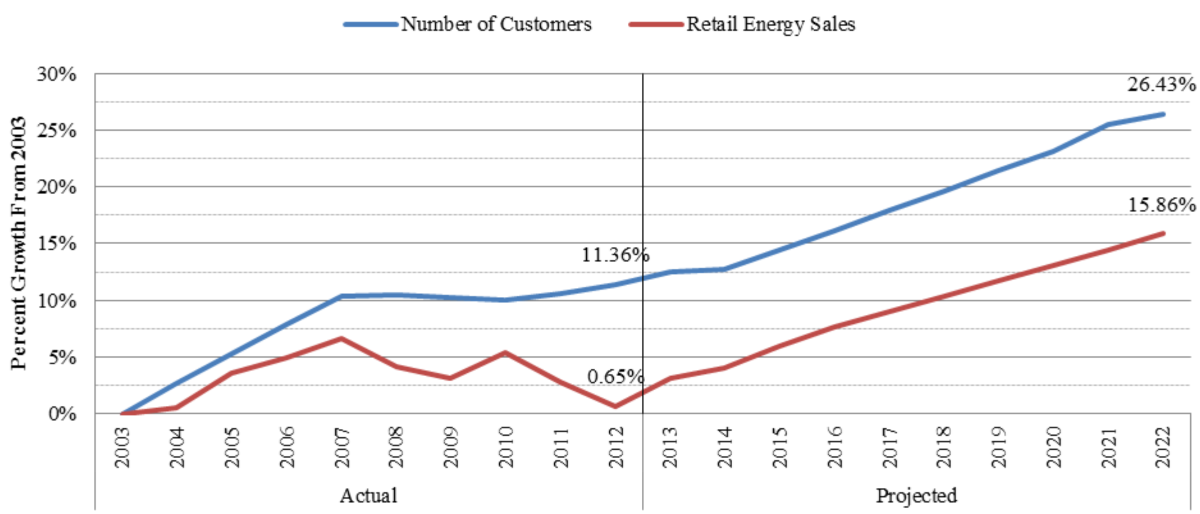
[1] Investor-owned utilities (IOUs) filing 2013 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF) which filed under its previous name, Progress Energy Florida, Inc., Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2013 TYSPs include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2013 TYSP.
[2] The Power Plant Siting Act is Sections 403.501 through 403.518, Florida Statutes
[3] Sections 366.80 through 366.85 and Section 403.519, F.S.

14,500 gigawatt-hours (GWh). Including these reductions, Florida is forecasted to experience by 2022 a net firm summer peak demand of 51,552 MW and annual net energy for load of 270,797 GWh.

Over the last ten years, the total number of electric customers in Florida has increased by 11.4 percent. Primarily this growth took place between 2003 and 2007, before the recession, after which customer growth plateaued, with the annual average growth rate dropping from 2.5 percent to a tenth of that figure, at 0.2 percent, including two years of slight negative growth. Forecasts estimate a higher rate of growth over the next ten years, at an annual average of 1.2 percent, below the average rate before the recession.

By comparison, retail energy sales in 2012 have only increased 0.6 percent over the past ten years. Retail energy sales followed a similar growth pattern as customer growth before 2007, but experienced an overall decline since the 2007 peak. Forecasts for energy sales also estimate a growth, at an annual average rate of 1.4 percent. This rate is also below the growth rate experienced before the recession, but is slightly higher than customer growth. Retail energy sales are anticipated to exceed the 2007 peak by 2016. Figure 1 details these trends below for number of customers and retail energy sales.

Figure 1: State of Florida - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 FRCC Regional Load & Resource Plan

Renewable Generation

Renewable resources continue to expand in Florida, with approximately 1,470 MW of renewable generation currently operating in Florida. Presently, municipal solid waste (MSW) and biomass each represent roughly a third of renewable generation in Florida. Other major types of renewable generation operating in the state include waste heat, hydroelectric, landfill gas, and solar.

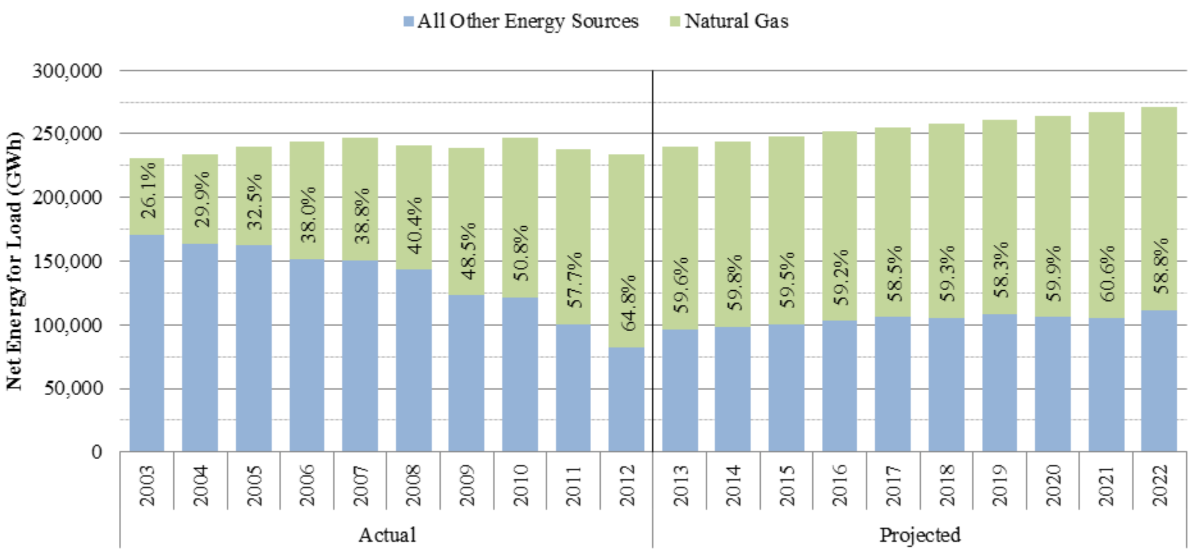
Executive Summary

Over the planning horizon, approximately 966 MW of additional renewable generation is planned in Florida. The majority of these additions are solar and biomass. While these new projects represent a significant increase from the existing total, renewable generation continues to provide a relatively small contribution towards the reduction of the state's reliance on fossil fuels.

Traditional Generation

Natural gas is anticipated to remain the dominant fuel over the planning horizon, with usage in 2012 increasing to 64.8 percent of the state's net energy for load (NEL), up from 57.7 percent of NEL in 2011. Figure 2 below illustrates the increasing use of natural gas as a generating fuel for the electricity production during the last ten years, and the projected use during the next decade. State-wide, natural gas usage is expected to decline slightly, on a percentage basis, from its current peak, to 58.8 percent in 2022. This is due to projected increases in nuclear generation, and a limited impact of new environmental compliance requirements.

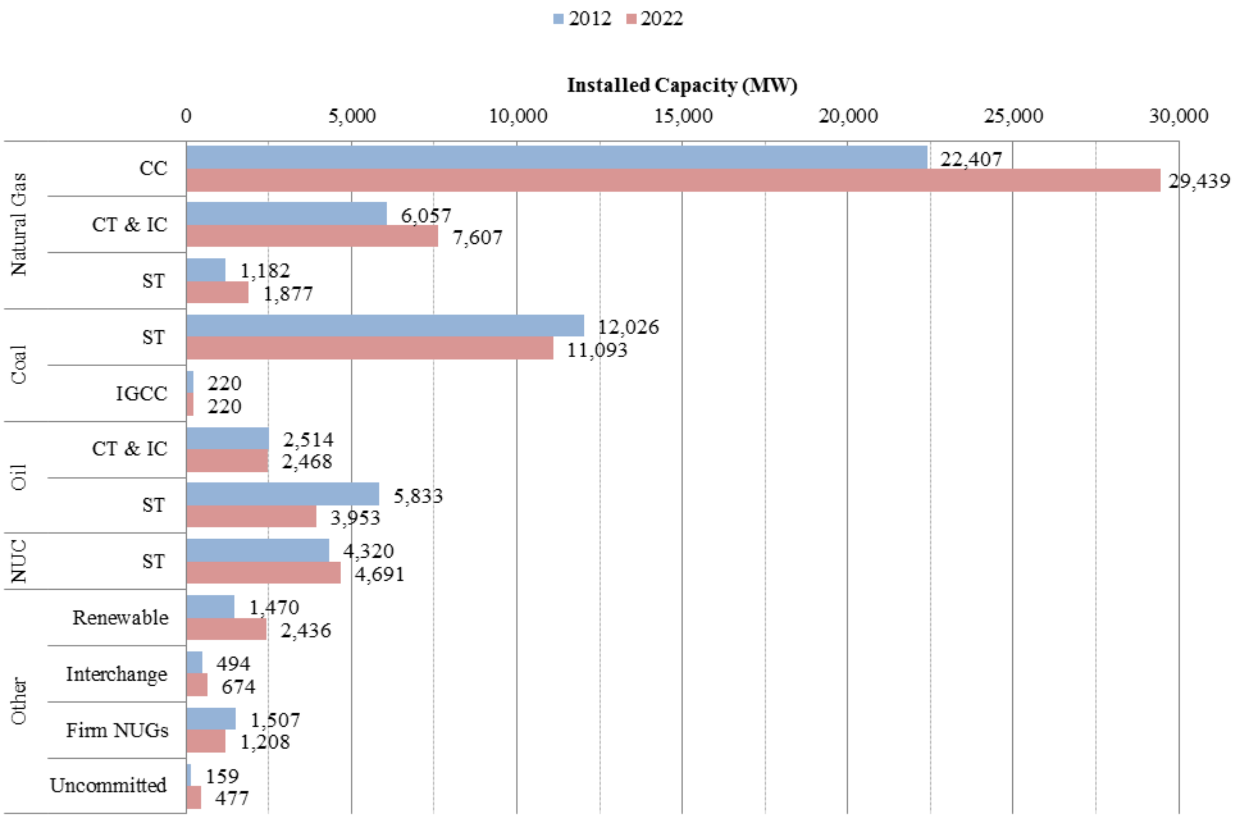
Figure 2: State of Florida - Natural Gas Usage (History & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 9,960 megawatts (MW) of new utility-owned generation added over the planning horizon. This figure represents an increase from last year's TYSPs, which estimated the need for about 7,200 MW new generation. Based on the 2013 Ten-Year Site Plans, Figure 3 below illustrates the present and future aggregate capacity mix of the State of Florida. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the ten-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of capacity within the state. Retirements primarily consist of oil-fired and coal-fired steam generation, in addition to DEF's Crystal River Unit 3 (CR3), one of the five existing nuclear units in Florida.

Figure 3: State of Florida - Installed Capacity (Existing & Projected)



Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan

Future Commission Actions

Florida's electric utilities must also consider environmental concerns associated with existing and planned generation to meet Florida's electric needs. The U.S. Environmental Protection Agency (EPA) has finalized or proposed several new rules in recent years that will have an impact on Florida's existing generation fleet, as well as on its proposed new facilities.

These EPA rules will limit allowable emissions from new and existing power plants for a variety of pollutants, including mercury, other heavy metals, organic toxics, particulates, sulfur oxides, and nitrogen oxides. While many facilities within the state already have sufficient emissions control technologies to comply with these rules, some will require installation of new equipment to bring generators into compliance. Other rules address concerns relating to cooling water's impact on aquatic life and the disposal of coal ash. All of these activities will require new investment and the potential for extended outages of some generating units, which will require careful planning to minimize any impact on system reliability.

Executive Summary

At this time, GPC's coal-fired Plant Scholz and DEF's Crystal River units 1 and 2 are the only plants anticipated to be retired as a result of any of these regulations. Additionally, DEF's Suwanee River Units 1-3, which can use either residual oil or natural gas, will cease residual oil operations in order to comply with the MATS rule. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and with a range between $2.4 and $5.5 billion, which may not encompass all associated potential costs.

As noted previously, the primary purpose of this review of the utilities' TYSPs is to provide information regarding new electric power plants to the DEP for its use in the certification process. Table 1 displays those generation facilities included in the 2012 TYSPs that have not yet received a certification under the PPSA by the Commission. Certification is generally anticipated at four years in advance of the in-service date for a natural gas-fired combined cycle unit.

Table 1: State of Florida - Proposed Generation Requiring Commission Approval

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
DEF	Unnamed CC 1	1,189	06/2018
DEF	Unnamed CC 2	1,189	06/2020
SEC	Unnamed CC 1	192	12/2020
SEC	Unnamed CC 2	192	12/2020

Source: 2013 TYSPs

While the Commission certifies transmission lines under the Transmission Line Siting Act (TLSA), there are none projected during the planning period that have not already been approved by the Commission.

Conclusion

The Commission has reviewed the 2013 TYSPs filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission does continue to monitor the increased dependence on natural gas for electricity production, and the impact of this reduction in fuel diversity on the state. While low prices for natural gas have made it the dominant fuel, its history of price volatility raises the specter of increased costs should there be disruptions in natural gas production, supply, or markets.

Based on its review, the Commission finds the 2013 TYSPs filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes. Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Introduction

The Ten-Year Site Plans (TYSPs or Plans) of Florida's electric utilities are 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. Because the TYSPs are considered to be planning documents and can contain tentative data, they may not necessarily contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their respective jurisdictions. Each utility is responsible for providing detailed information based on individual assessments during certification proceedings under the Power Plant Siting Act (PPSA), Sections 403.501-403.518, Florida Statutes (F.S.), or the Transmission Line Siting Act (TLSA), Sections 403.52-403.5365, F.S. In addition, other regulatory processes may require utilities to provide additional information as needed.

Statutory Authority

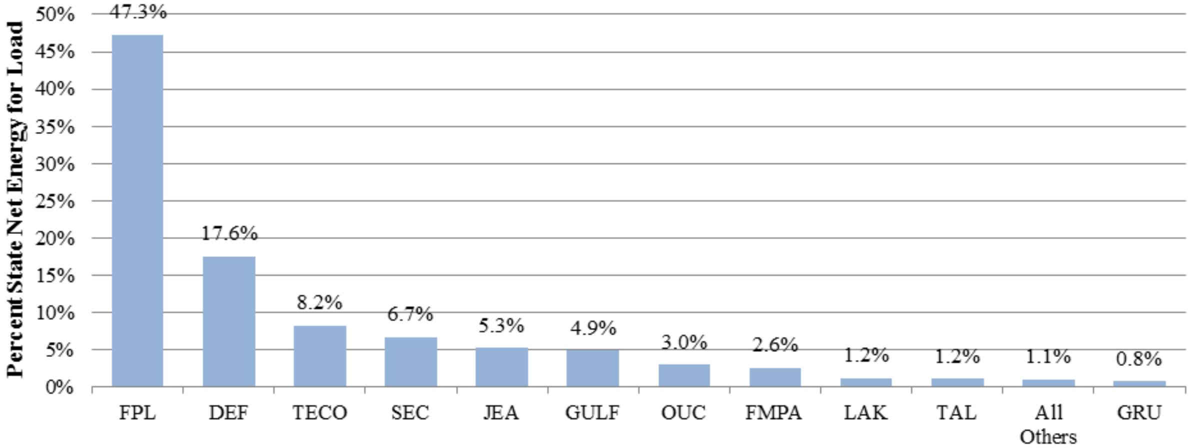
Section 186.801, F.S., requires that all major generating electric utilities submit a TYSP to the Commission for annual review. Section 377.703(2)(e), F.S., requires the Commission to analyze these plans and provide natural gas and electricity forecasts to the Department of Agriculture and Consumer Services (DACS). 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.

Florida is served by 58 electric utilities, including 5 investor-owned utilities (IOUs), 35 municipal utilities, and 18 rural electric cooperatives. Only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a TYSP, at least once every two years. In 2013, eleven utilities filed TYSPs, including 4 IOUs, 6 municipal utilities, and 1 rural electric cooperative.[4]

Figure 4 below illustrates each TYSP utility's representative share of the state's net energy for load for 2012. In total, the investor-owned TYSP utilities represent 78 percent of net energy for load (NEL). Those utilities which are not required to file a TYSP make up the approximately 1 percent of the state's NEL.

[4] IOUs filing 2013 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF) which filed under its previous name, Progress Energy Florida, Inc., Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2013 TYSPs include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2013 TYSP.

Figure 4: TYSP Utilities - Share of State Net Energy for Load



Source: 2013 TYSPs, 2013 FRCC Load & Resource Plan

As outlined in the Commission's rules, each utility's TYSP contains projections of the utility's electric power needs, fuel requirements, and general location of proposed power plant sites and major transmission facilities. The utilities provide historic and projected information on existing generating capacity, customer base and energy usage, impact of demand-side management, fuel consumption, fuel diversity, anticipated reserve margin, and proposed new generating units and transmission.

In accordance with Section 186.801, F.S., the Commission performs a preliminary study of each TYSP and makes a determination as to whether it is suitable or unsuitable. This determination is non-binding, and is made in recognition that the information provided is tentative, and is subject to change by the utility upon written notice. The results of the Commission's study are contained in this report, Review of the 2013 Ten-Year Site Plans, and are forwarded to the DEP for use in subsequent power plant siting proceedings.

Information Sources for the Report

Contained in each utility's TYSP is a series of required tables which provide detailed information on a number of items. This information, supplemented by additional data requests, provides the basis of the Commission's review.

The Florida Reliability Coordinating Council (FRCC) is also an important source of information for the Commission's review. Each year, the FRCC publishes its Regional Load and Resource Plan which contains aggregate data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions, both for Peninsular Florida and for the state as a whole. The primary focus of the FRCC is the reliability of the electrical system for Peninsular Florida. In addition to its *2013 Regional Load and Resource Plan*, the Commission used the FRCC's *2013 Reliability Assessment* as a resource in the production of this review. The Commission held a public workshop on September 25, 2013, to facilitate discussion of the annual planning process and the Regional Load & Resource Plan and to allow for public comments on the TYSPs that were filed with the Commission. In addition to the FRCC, the

Introduction

Sierra Club, also representing Earthjustice, and Southern Alliance for Clean Energy (SACE) made presentations at the workshop. Energy Conservation was the primary topic, with discussion on various changes in building codes, increased customer education, and utility programs reviewed by the Commission. Both the Sierra Club and SACE were aware of the Commission's open dockets to review utility energy conservation goals later next year.

Structure of the Report

This report is divided into multiple sections. The Statewide perspective provides a look at the impact of all planned unit additions to the State as a whole, and is intended as a resource for those seeking an understanding of Florida's energy systems. Individual utility reports focus on the issues facing each electric utility and its unique situation. Lastly, Appendix A contains comments received from various review agencies, local governments, and others that have been collected and included in this report.

Conclusions

As discussed in each of the individual utility's reviews, the Commission's review of the eleven reporting utilities' 2013 TYSPs finds them all suitable for planning purposes. Through the review process, the Commission has determined that the projections of load growth appear reasonable, and that reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost.

Since the TYSP is 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 any docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Statewide Perspective

Load and Energy Forecast

Forecasting load growth is the first component of system planning for Florida's electric utilities. In order to maintain a reliable system, utilities must stay abreast of changes in customer base as well as trends in demand and energy consumption. Utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs, taking into consideration the number and type of customers served, changes in customer usage patterns, impacts of mandated energy efficiency standards, new technologies, and demand-side management (DSM) programs.

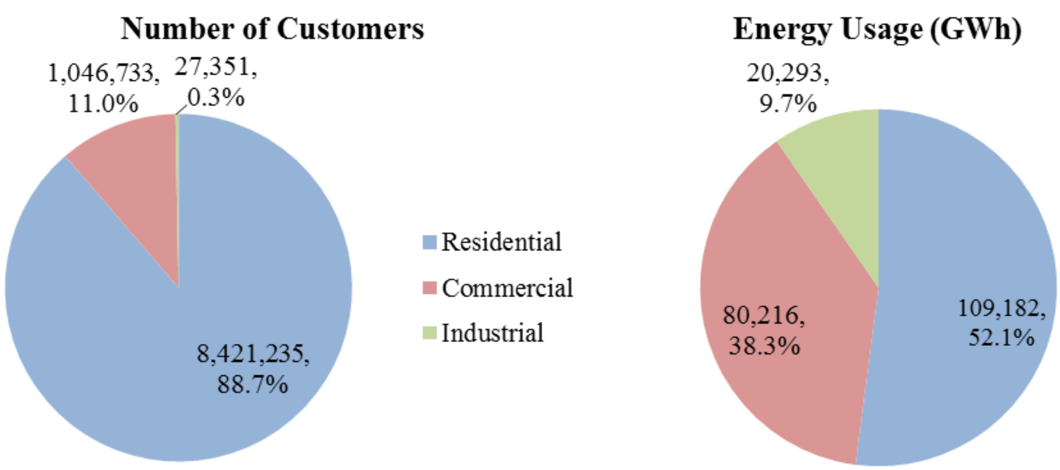
Historical data forms the foundation for utility load and energy forecasts. These sets of data include energy usage patterns, trends in population growth, economic variables, and weather data for each utility's service territory. Econometric forecast models are then used to quantify the historical impact of population growth, economic conditions, and weather on energy usage patterns.

Finally, sets of forecast assumptions on future population growth, economic conditions, and weather are assembled and together with the forecast models, yield the final demand and energy forecasts. Each utility's peak demand and energy forecasts serve as a starting point for determining if and when new capacity additions are needed to reliably and efficiently serve the anticipated load.

Florida's Electricity Customer Composition

Florida is dominated by residential electric customers, which make up a majority in both number of customers and retail energy sales, as shown in Figure 5 below. While commercial and industrial customers may be lower in number, they consume far more per customer, and combined represent the other half of energy consumed in Florida.

Figure 5: State of Florida - Number of Customers and Energy Usage by Class



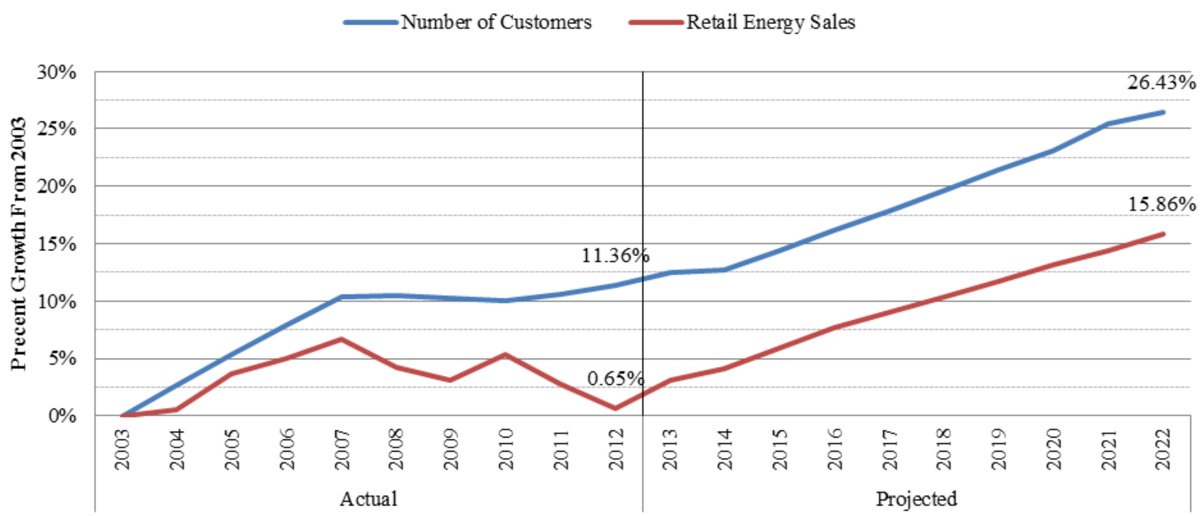
Source: 2013 FRCC Regional Load & Resource Plan

Load and Energy Forecast

Growth in Customer Base and Consumption

Florida traditionally has been a high growth state, with significant annual increases in both customers and retail energy sales. The impact of the financial crisis changed these tendencies, with customer growth plateauing and retail energy sales declining from their 2007 peak, with an annual increase only in 2010, associated with extreme winter weather. Over the last ten years, Florida has experienced a growth in customers of 11.36 percent, but retail energy sales in 2012 were only 0.65 percent higher than 2003. These trends are illustrated in Figure 6 below.

Figure 6: State of Florida - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 FRCC Regional Load & Resource Plan

Customer growth and usage is projected to increase throughout the planning period, although at a slower pace than at the beginning of the last decade, with retail energy sales expected to exceed its 2007 peak by 2016. This is primarily based on assumptions of population growth and improving economic indicators. The current gap between number of customers and retail energy sales is projected throughout the planning period.

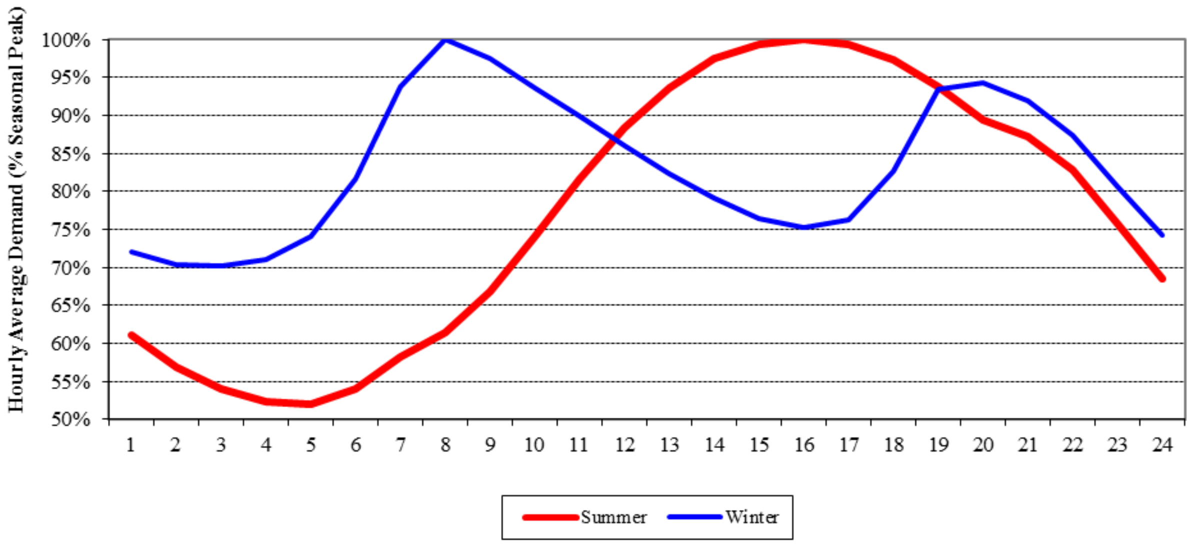
Seasonal Peak Demand Forecast

Since there exists no economically feasible means to store electricity at the grid-scale, electric utilities must supply electricity near instantaneously to the time of its consumption. For a majority of the time, system demand is significantly less than the daily peak. However, system peak demand determines the timing of new generation needs, and is driven by seasonal weather patterns. With a growing customer base dominated by residential customers, both the rate of growth and usage patterns are important considerations in planning sufficient future generation to meet the state's projected customer load.

Load and Energy Forecast

Figure 7 illustrates typical daily load curves for each season, which shows evidence of the influence of residential customers. In summer, air-conditioning demand causes a steady climb in the morning and a peak in early evening, before declining into the evening. In contrast, winter's demand curve is dominated by electric heating and water heating, causing a rapid peak in mid-morning and a second peak in the late evening.

Figure 7: State of Florida - Daily Load Curve Example

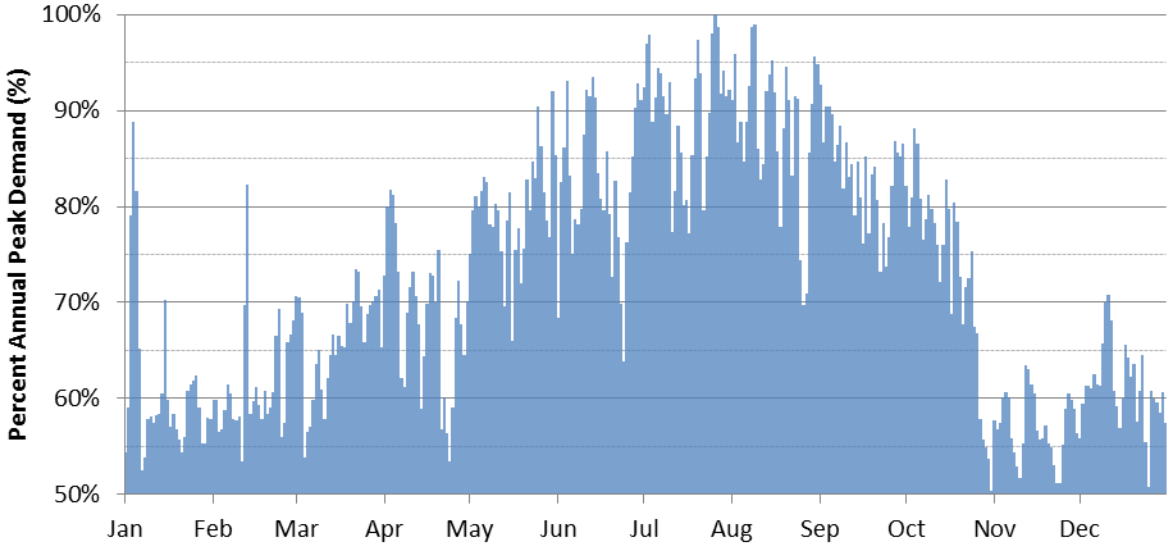


Source: TYSP Utilities Data Response

Florida is typically a summer-peaking state, meaning that the summer peak demand generally controls the amount of generation required. While winter peak demands tend to be greater than summer, the higher peak is offset by the increased winter rating of power plants, which can take advantage of lower ambient air and water temperatures to produce more electricity from the same generating unit. During summer peak demand, higher temperatures instead can decrease generation, as high water temperatures may reduce not only the quality, but quantity of cooling water available based on environmental permits.

As with daily load, there is a great variation in seasonal peak load. Figure 8 below illustrates this for 2012, showing daily peak demand as a percentage of the annual peak. As demonstrated in the figure, winter peaks tend to be shorter duration events, while Florida's summer season has longer periods of high peak demands. The periods between the seasonal peaks are referred to as "shoulder months," and utilities take advantage of these periods of relatively low demand to perform maintenance without impacting their ability to meet the daily peak demand.

Figure 8: Generating IOUs - 2012 Daily Peak as a Percent of Annual Peak Demand



Source: 2013 TYSP Utilities Data Response

In general, a major controlling factor to seasonal peak demand is short-term weather conditions. While utilities forecast annual peak demand based upon historic factors, customer counts, and normalized weather patterns, utilities also continuously monitor weather conditions in their service territory and prepare for any increases (or decreases) in customer demand. By closely monitoring the weather situation, utilities can fine tune maintenance schedules to ensure the highest unit availability during the utility's peak demand.

Impact of Electric Vehicles

The FPSC also continues to examine the effects of plug-in electric vehicles (EVs) on the electric grid. EVs include any vehicles that draw some or all of their energy from the electric grid, as opposed to hybrid electric vehicles which, while conserving some energy through the braking process, still rely entirely on gasoline or diesel for their energy.

At present, Florida Department of Highway Safety and Motor Vehicles (FHSMV) data indicates that there were approximately 3,818 plug-in EVs registered in Florida as of May 1, 2013, with an additional 861 low-speed vehicles (such as electric golf carts and other neighborhood electric vehicles) registered.[5] Since the FHSMV reports 18.8 million vehicles of all types registered in Florida as of August 2013, EVs are still only approximately 0.025 percent of that total. Table 2 shows the growth in the registrations of plug-in EVs since 2008, the year the first modern EV, the Tesla Roadster, was made available.

[5] FHSMV provides VIN data to Polk Consulting, who decode VINs in order to establish make and model. The numbers include all electric-only vehicles, as well as the Chevy Volt, a plug-in hybrid. The statistics do not differentiate clearly between other plug-in hybrid vehicles and gasoline-only hybrids, but these data should capture most of the plug-in vehicles registered in the state of Florida.

Table 2: State of Florida - Plug-in EVs Registered in Florida (2008 - 2013)

Vehicle Category	2008	2009	2010	2011	2012	2013*	Total
Plug-in EVs	1	37	31	465	1,868	1,416	**3,818**
Low-Speed Vehicles	237	176	92	121	137	98	**861**
Total	**238**	**213**	**123**	**586**	**2,005**	**1,514**	**4,679**

* Through May 1, 2013.

Source: Polk Consulting, FHSMV.

Table 3 shows TYSP utilities' projections of the number of EVs in their service territories through 2022. While these numbers are presently limited, utilities project them to rise sharply over the next ten years, to a total of 315,958 by 2022. Even if that figure is reached, however, it would still represent less than 2 percent of projected vehicle registrations in Florida in 2022.

Table 3: TYSP Utilities - Estimates of the Number of Plug-In EVs by Service Territory

	Utility							
Year	**FPL**	**DEF**	**TECO**	**GPC**	**JEA**	**OUC**	**TAL**	**Total**
2012	2,020	238	176	169	9	537	16	**3,165**
2013	5,006	1,054	NA	685	12	1,030	32	**7,819**
2014	9,669	2,361	NA	1,344	20	1,624	58	**15,076**
2015	16,413	4,045	NA	2,119	38	2,689	98	**25,402**
2016	25,490	6,274	NA	3,015	214	4,037	157	**39,187**
2017	39,461	9,500	NA	3,998	431	5,685	235	**59,310**
2018	53,896	13,816	NA	5,141	651	7,646	329	**67,663**
2019	72,139	19,337	NA	6,447	876	9,937	461	**109,197**
2020	107,352	26,204	NA	7,921	1,104	12,574	645	**155,800**
2021	159,439	34,576	NA	9,566	2,006	15,570	838	**221,995**
2022	236,695	45,184	NA	11,248	2,924	18,859	1,048	**315,958**

Source: TYSP Utilities Data Response.

Table 4 shows the total projected energy consumption of the TYSP utilities associated with EVs during the same time frame. While the additional consumption is quite modest at present, utilities project it growing to almost 2,000 GWh in 2022.

Table 4: TYSP Utilities - Estimates for EV Annual Energy Consumption (GWh)

Year	EV Contribution to Annual Energy Consumption (GWh)							
	FPL	DEF	TECO	GPC	JEA	OUC	TAL	Total
2012	13	1.3	NA	0.7	0.0	0.2	5	**20**
2013	31	5.2	NA	2.8	0.1	0.5	11	**51**
2014	62	10.7	NA	5.5	0.2	1.0	19	**98**
2015	110	16.8	NA	8.7	0.4	1.6	33	**171**
2016	173	23.7	NA	12.4	2.3	2.4	53	**267**
2017	261	32.2	NA	16.4	4.8	3.4	79	**397**
2018	358	43.6	NA	21.1	7.6	4.6	111	**546**
2019	480	58.0	NA	26.5	10.8	6.0	155	**736**
2020	688	75.7	NA	32.5	14.2	7.5	218	**1,036**
2021	984	97.0	NA	39.3	26.9	9.3	283	**1,440**
2022	1,408	122.8	NA	46.2	40.9	11.3	354	**1,983**

Sources: TYSP Utilities Data Response

The effect these additional EVs will have on peak system demand is more difficult to determine. Due to numerous uncertainties regarding EV deployment, including at what times they will be charged and the possibility that EV charging may be shifted away from peak if necessary, most TYSP utilities were unable to project EVs effects at system peak. TYSP utilities did not report any current reliability or safety issues resulting from EVs, nor any needed system upgrades necessitated by EV deployment. As EV deployment moves forward, the effects of EVs on system peak should become clearer.

Demand Side Management

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering DSM and conservation programs designed to use fewer resources at lower cost.

Florida Energy Efficiency and Conservation Act

The Florida Legislature directed the Commission to encourage utilities to decrease the growth in seasonal peak demand and energy consumption in Sections 366.80 through 366.85 and Section 403.519, F.S., known as the Florida Energy Efficiency and Conservation Act (FEECA). Under FEECA, the Commission is required to set goals for demand and energy reduction for 7 electric utilities, namely the 5 investor-owned electric utilities (including Florida Public Utility

Company, which is a non-generating utility and therefore does not file a TYSP) and 2 municipal electric utilities (JEA and OUC).[6] These utilities represent 86 percent of sales in Florida.

The seven FEECA utilities currently offer DSM programs to residential, commercial, and industrial programs. Energy audit programs provide a first step for utilities and customers to evaluate conservation opportunities and serve as the foundation for other programs.

The last annual demand and energy goal-setting proceeding was completed in December of 2009, providing annual goals for the period of 2010 through 2019. To meet the requirement to set goals at least once every five years, the Commission must establish annual goals for the 2015 through 2024 period by the end of 2014. The Commission already established dockets for each of the seven FEECA Utilities in July 2013, with hearing dates set for July 2014, and a final decision by the Commission expected by October 2014.

Demand Side Management Programs

DSM Programs generally fall into three categories: interruptible or curtailable load (IL), load management (LM), and conservation. The first two are generally considered dispatchable, and are referred to as Demand Response (DR), meaning that the utility can call upon them during a period of peak demand, but otherwise they are not in active use. In contrast, conservation measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible or curtailable load is achieved through the use of agreements with large customers to allow the utility to interrupt selected portions of the customer's load during periods of peak demand. Interrupted or curtailed customers could make up for this generation by reducing their own industrial processes or by activating back-up generation. In exchange for the ability to reduce their electrical load, the utility usually offers such customers a discounted rate for energy or other credits which are paid for by all customers.

Load management programs involve the installation of a device that can interrupt a customer's appliance(s) for a short duration during a period of peak demand. These interruptions tend to have less notice than those provided to interruptible customers, and generally do not fully disconnect customers, but interrupt an individual appliance. Normally, interruptions are kept to short periods and are cycled between groups of customers. Due to the nature of the program, certain devices would be more appropriate to handle different seasonal demands. For example, air conditioning units would be interrupted to reduce a summer peak, while water heaters being interrupted may contribute more towards reducing a winter peak. As of 2013, over 3,145 MW of interruptible load and load management is available for summer peak, and is anticipated to expand to 3,618 MW by 2022.

In addition to active measures, customer-based conservation measures can have an impact on peak demand without requiring activation by the utility. These passive conservation measures typically involve improving a home or business' building envelope, such as greater insulation and energy-efficient windows, or installing more efficient appliances. These energy efficiency improvements decrease the customer's load at all times without requiring an

[6] Sections 366.82(1)(a), F.S.

interruption or reduction in service, and also have an impact on annual energy consumption. As of 2013, over 3,592 MW of cumulative conservation for summer peak demand has been installed, increasing to 5,009 MW by summer of 2022.

Projected Peak Demand & Energy Usage

Based on all of the factors and considerations above, Figure 9 below illustrates the historic and projected seasonal peak demand and annual energy consumption for the state of Florida. While seasonal peak demand is the instantaneous usage of a customer on the system, annual energy consumption addresses the total cumulative demand on the system over time, which determines the type of units required and the resulting amount of fuel consumed.

For each category the impacts of conservation (including some self-service generators), and for seasonal peak demand, load management programs, and interruptible/curtailable load is shown. The total demand or total energy for load represents what otherwise would be served if not for the impact of demand response and conservation programs. The net firm demand is used as a planning number for the calculation of generating reserves.

For historic values of seasonal peak demand, the actual rates of activation for interruptible/curtailable load and load management are shown. The amount of available demand response exceeded the activated amount shown, but was not called upon due to sufficient generation assets being available during the peak hour. Generally, residential load management programs have been called upon to a limited degree during peak periods, with a lesser amount of interruptible/curtailable load and commercial/industrial load management activated. The summer of 2008 and winter of 2009 are exceptions to this trend, when a larger portion of the available demand response resources were called upon.

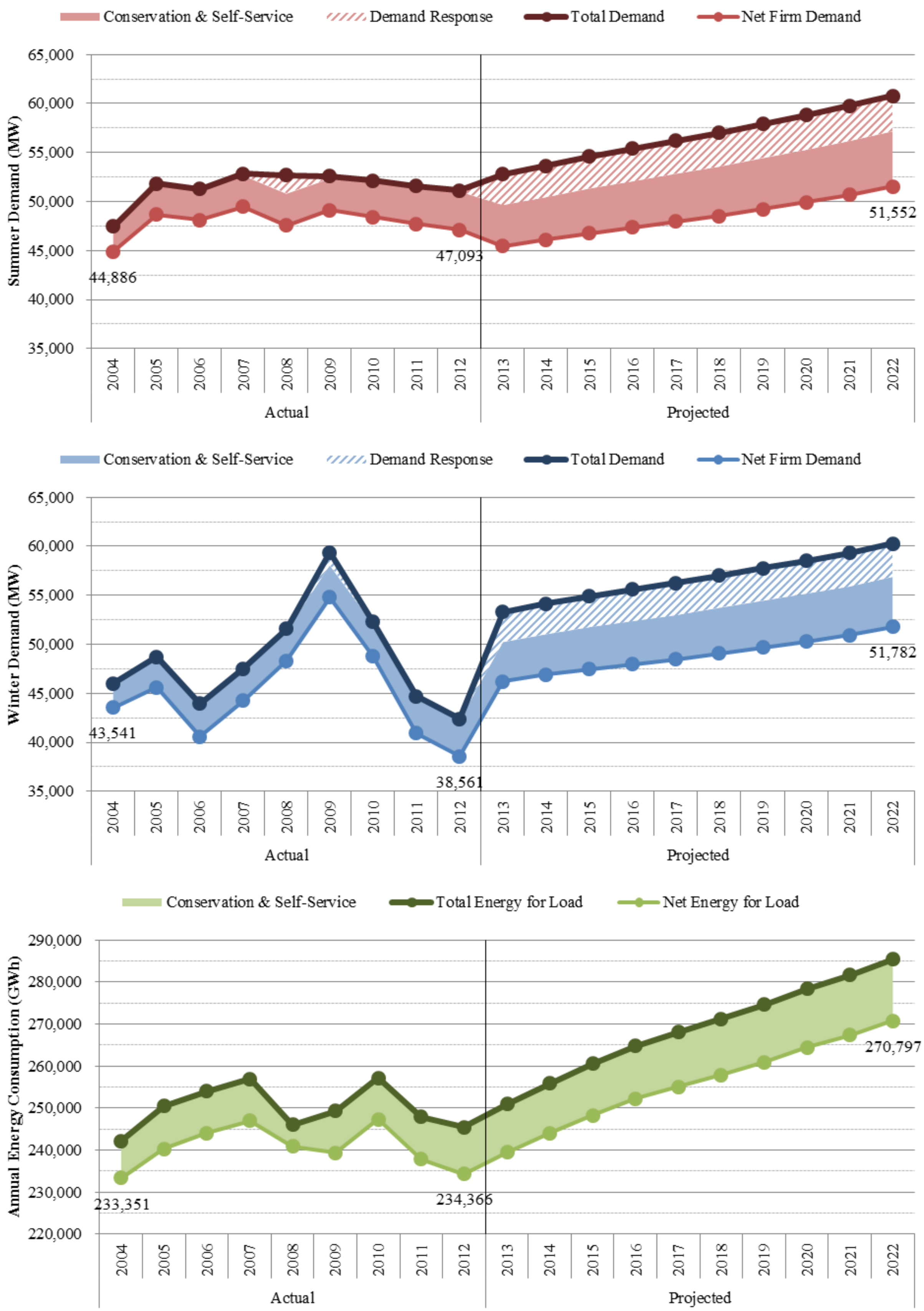
For forecasted values of seasonal peak demand, it is assumed that demand response will be activated during the peak period. However, if companies have sufficient generating assets and it is economical to serve all customer load, demand response resources may not be activated or only partially activated based upon each utility's future operating conditions.

It should be noted that the forecasts shown are based upon normalized weather conditions, while historic demand and energy forecasts represent the actual impact of severe or mild weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in summer and electric heating in winter, so both seasons experience a great deal of variability.

While Figure 9 shows historic and forecasted winter peak demand values as the highest seasonal values, summer peak dominates planning for most TYSP Utilities because most generating units are sensitive to ambient temperature and are able to generate more in the winter than in the summer. This is illustrated later in the determination of the generating reserve margin.

Load and Energy Forecast

Figure 9: State of Florida - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

Accuracy of Energy Forecasts

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of past retail energy sales forecasts. The review compared actual retail energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2012 energy sales were compared to the projected 2012 value from forecasts made in 2009, 2008, and 2007. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy using a five year rolling average. For example, the 2012 error rate looks at the difference between actual retail energy sales for 2012 through 2008, drawing upon projections made between 2009 through 2003. An average error with a negative value indicates a tendency to under-forecast, while a positive value represents an over-forecasting of retail energy sales. Absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under/over-forecast.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts

TYSP Year	Five Year Period	Forecast Error (%)	
		Average	Absolute Average
2009	2008 - 2004	1.79%	3.56%
2010	2009 - 2005	5.01%	5.71%
2011	2010 - 2006	8.31%	8.31%
2012	2011 - 2007	11.91%	11.91%
2013	2012 - 2008	15.10%	15.10%

Source: 2004 - 2013 TYSPs

Table 5 above illustrates the historical forecast error for the combined 2013 through 2009 TYSPs. These correspond to actual data from 2012 through 2008. Overall, a pattern of increasing error in retail sales forecasts is shown, with error over 10 percent based in 2011 and 2012. The high error rate, which has increased each year for the past five years, seems to be associated with the unexpected impacts of the recession on retail energy sales in Florida, both from reduction in the state's growth rate, but also from decreased usage per capita. As the five year rolling average progresses and includes more years post-recession, the error values should subside.

Table 6 below provides a more detailed data set used to calculate the average error rating, showing forecasts made between one and six years prior. A significant increase in error is evident in 2008 and beyond, with forecasts made post 2009 improving in accuracy and approaching historic levels of error. As this analysis moves forward and begins to use forecasts developed after the beginning of the recession, the error rate should fall back to typical levels.

Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis

Year	Years Prior						Average Error	Absolute Average Error
	6	5	4	3	2	1		
2004	-	-4.96%	-3.06%	0.31%	-0.47%	1.05%	**-2.57%**	**2.78%**
2005	-5.79%	-4.00%	-0.66%	-0.60%	0.75%	0.93%	**-1.75%**	**1.75%**
2006	-3.24%	0.02%	1.08%	2.35%	2.48%	2.42%	**1.15%**	**1.15%**
2007	0.61%	2.31%	3.54%	3.63%	4.25%	3.09%	**3.16%**	**3.16%**
2008	7.02%	8.40%	8.55%	9.97%	9.24%	8.34%	**8.97%**	**8.97%**
2009	11.97%	12.17%	14.50%	13.93%	12.70%	10.19%	**13.53%**	**13.53%**
2010	12.94%	15.58%	14.89%	13.70%	10.56%	-0.73%	**14.72%**	**14.72%**
2011	21.39%	20.63%	19.92%	16.86%	3.65%	-0.06%	**19.14%**	**19.14%**
2012	26.30%	25.97%	23.03%	8.47%	3.90%	3.70%	**19.15%**	**19.15%**

Source: 2004 - 2013 TYSPs

As indicated by this high error rate, utilities projected increased need for energy that has not materialized due to the recession. The TYSP utilities have responded to changing circumstances by delaying or cancelling new generation and taking opportunities to modernize existing plants, as discussed in previous annual reviews of the TYSPs.

Renewable Generation

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

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

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes, to also provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. The Section 366.91(2)(b), 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 1,470 MW of firm and non-firm generation capacity, which represents 2.2 percent of Florida's overall generation capacity of 58,200 MW in 2012.[7] Table 7 below summarizes Florida's existing renewable energy sources.

Table 7: State of Florida - Existing Renewable Resources

Renewable Fuel Type	Summer Net Capacity (MW)
Land Fill Gas	40
Municipal Solid Waste	466
Biomass	415
Solar	178
Hydro	63
Waste Heat	308
Wind	0
Total	**1,470**

Source: 2013 FRCC Regional Load & Resource Plan, TYSP Utilities Data Responses

[7] Total MW capacities are based off summer ratings.

Renewable Generation

Of the total 1,470 MW of renewable generation, approximately 434 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 fueled power plant construction.

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

Non-Utility Renewable Generation

The majority of Florida's existing renewable energy generation, approximately 84 percent, comes from non-utility generators. In 1978 the U.S. Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from qualifying QFs at the utility's full avoided cost. Section 366.051, F.S., provides:

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

If a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output under a firm contract. Rule 25-17.230, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's TYSP. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers to select the payment option that best fits its financing requirements and provides a basis from which negotiated contracts can be developed. On June 25, 2013, the Commission approved standard offer contracts resulting in the continuous offering of nearly 3,700 MW for Florida's four largest IOUs.

As previously discussed a large amount 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.

Utility Owned Renewable Generation

Utility owned renewable generation also contributes to the State's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities is considered non-firm for planning purposes.

Renewable Generation

A significant portion of the utility owned renewable generation is from three solar energy facilities, totaling 110 MW, operated by FPL. The three solar projects, 2 solar PV facilities and 1 solar thermal facility, were approved for cost recovery pursuant to Section 366.92, F.S. which has since been revised, but previously stated:

> In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of generation, up to a total of 110 megawatts statewide.

In 2008, the Commission approved a petition by FPL seeking eligibility for cost recovery pursuant to the referenced Statute. At the time of its filing, FPL estimated that the three solar facilities would cost an additional $573 million above traditional generation costs over the life of the facilities. Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $.45/kWh in 2012.

Since full operation began the two solar PV facilities have operated largely as expected; however, the solar thermal facility has experienced multiple outages which have hindered its performance. Based on actual data collected from the three facilities, the maximum output does not appear to be coincident with the system's peak demand.

Hydroelectric units at two sites, one owned by the City of Tallahassee Utilities, and one operated by the Federal government, supply 63 MW of renewable capacity. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

Customer Owned Renewable Generation

With respect to customer owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of the discussed Rule, customer owned renewable generation attributed 3 MW of renewable capacity. As of 2012, approximately 44 MW of renewable capacity from nearly 5,300 systems had been installed statewide. Table 8 below, summarizes the growth of customer owned renewable generation interconnections.

Table 8: Renewable Generation Interconnections

Year	2008	2009	2010	2011	2012
Facilities	577	1,625	2,833	3,994	5,296
MW	3	13	20	29	44

Source: Annual Net Metering Reports

Planned Renewable Additions

Florida's utilities plan to construct or purchase an additional 966 MW of renewable generation over the ten-year planning period. Table 9 summarizes the planned renewable capacity increases by generation type.

Table 9: State of Florida - Planned Renewable Resource Additions

Renewable Fuel Type	Summer Net Capacity (MW)
Land Fill Gas	12
Municipal Solid Waste	125
Biomass	470
Solar	359
Hydro	0
Waste Heat	0
Wind	0
Total	**966**

Source: 2013 FRCC Regional Load & Resource Plan, TYSP Utilities Data Response

Of the 966 MW of planned renewable capacity, 510 MW are projected to be from firm resources. All of the projected firm capacity additions are from renewable contracts with non-utility generators. Table 10 summarizes the firm capacity renewable resources that are planned over the ten-year horizon. The remaining planned capacity from renewable resources is projected to be from non-firm resources including several 50 MW solar facilities.

Table 10: State of Florida - List of Planned Renewable Firm Capacity

Purchasing Utility	Facility Name	Fuel Type	Capacity (MW)	In-Service Date
FPL	EcoGen Clay	OBS	60	2021
FPL	EcoGen Martin	OBS	60	2021
FPL	EcoGen Okeechobee	OBS	60	2021
FPL	Solid Waste Authority of Palm Beach #2	MSW	70	2016
GRU	Gainesville Renewable Energy Center	WDS	100	2014
DEF	FB Energy	AB	60	2013
DEF	Transworld Energy	WDS	40	2013
DEF	EcoGen Polk	WDS	60	2014
Total			**510**	

Source: TYSP Utilities Data Responses

More than 170 MWs of contracted firm renewable capacity are projected to expire within the ten-year planning. 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.

Renewable Outlook

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. (Navigant) to prepare a detailed assessment of Florida's renewable potential. Navigant's assessment identified several key drivers that impact renewable energy development in Florida. Three of the "key drivers" were the cost of natural gas, the cost of CO_2, and the adoption of a Renewable Portfolio Standard (RPS).

Under a scenario considered to be favorable in fostering renewable generation, Navigant assumed natural gas prices between $11-$14/MMBTU, CO_2 emission costs ($2/ton initially, then scaling to $50/ton by 2020) and the adoption of an RPS in Florida. At this time, natural gas prices are projected at $3.88/MMBTU in 2013, there is no current federal pricing for CO_2 emissions, and no RPS legislation has been enacted. Therefore, current market conditions do not favor the development of renewable generation.

Even with these difficulties, Florida's renewable generation is projected to increase over the planning period. Renewable generation contributes to the state's fuel diversity, as discussed in the next chapter, and reduces dependence upon fossil fuels. While current economic conditions may prevent more expensive forms of renewable generation, those cost-effective forms of renewable generation will continue to increase the state's share of renewable generation.

Traditional Generation

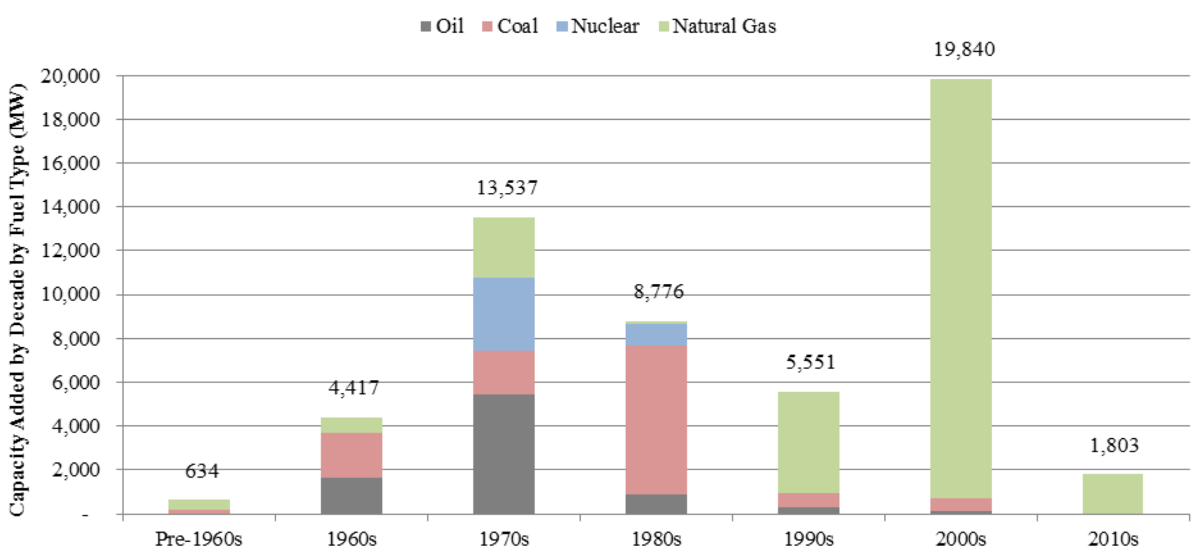
While renewable generators contribute to the state's generating capacity, a majority is made up of fossil-fueled steam and turbine generators that have been added to the grid over the last several decades. Due to forecasted increases in peak demand, further fossil-fired generation is anticipated over the planning horizon.

Historically, Florida's utilities relied upon oil-fired generation as the primary source of electricity until the increase in oil prices associated with the oil embargo. Since that time, Florida's utilities have sought a variety of other fuel sources to diversify the generating capacity and economically serve Florida's electric customers. Solid fuels, such as coal and nuclear, were utilized in greater quantity. Finally, natural gas has emerged as the dominant generating fuel. The swings of fuel prices, availability, environmental concerns, and other factors have resulted in a variety of capacity on Florida's existing system.

Existing Generation Resources

Florida's generating fleet includes incremental new additions to the historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to continue safe operation. Figure 10 below illustrates the decade currently operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 10: State of Florida - Generation Capacity Additions by Fuel Type and Decade



Source: 2013 FRCC Regional Load & Resource Plan

Traditional Generation

The existing generating fleet will be impacted by several events over the planning period. Retirements, including Crystal River 1 through 3 and Scholz 1 and 2, will reduce the existing fleet, while modernizations will replace older generation with newer, more efficient resources, and several units may have to install new pollution control equipment that may reduce net capacity. These items are discussed below.

Impact of EPA Regulations

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with changing environmental requirements. During the past several years, the EPA has finalized or proposed several rules which will impact both existing and planned generating units in the state. Potential environmental requirements and their associated costs must be considered to fully evaluate any new supply-side resources, as well as the maintenance and dispatch of existing generating units.

Four EPA rules are anticipated to potentially affect electric generation in Florida:

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

- Cross-State Air Pollution Rule (CSAPR) - Requires 28 states, including Florida, to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within these states. Florida is only subject to the rule's seasonal NOx emissions requirements. Due to ongoing litigation, the only costs utilities reported associated with CSAPR are stranded costs.

- Cooling Water Intake Structures (CWIS) - Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating facilities. All existing electric generators that use water for cooling with an intake velocity of at least two million gallons per day must meet impingement standards.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is disposed.

At this time, GPC's coal-fired Plant Scholz units 1 & 2 and DEF's Crystal River units 1 & 2 are the only plants anticipated to be retired as a result of any of these regulations. Additionally, DEF's Suwanee River Units 1-3, which can use either residual oil or natural gas, will cease residual oil operations in order to comply with the MATS rule. GPC has estimated that the costs for complying with the MATS Rule will make the operation of Plant Scholz uneconomical, and it will cease operation on April 1, 2015. Crystal River Units 1 and 2 are expected to cease operation in April of 2016, following a one-year MATS extension to perform transmission upgrades needed to take the units offline without affecting reliability.

For many of the plants that will remain in operation, these new rules will result in an increased cost of operations. Each utility will need to evaluate whether these additional costs or new operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 11 below.

Table 11: TYSP Utilities - Cost Estimates of EPA Rule Compliance (2013-2022)

Utility	Preliminary Total Cost Estimates ($ Millions)				
	MATS	CSAPR	CWIS	CCR	Total
Florida Power & Light	$226	0	$122-$1,515	Unavailable	$348-$1,741
Duke Energy Florida (Capital Costs Only)	85-130*	0	80-1,200	Unavailable	165-1,330
Tampa Electric Company	18.6	0	860	$141**	1,020
Gulf Power Company	544-843	0	38-125	255-414	837-1,382
Florida Municipal Power Agency	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Gainesville Regional Utilities	Unavailable	Unavailable	0	Unavailable	Unavailable
JEA	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Lakeland Electric	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Orlando Utilities Commission	2.3	$11	Unavailable	13	26
Seminole Electric Cooperative	0	0	Unavailable	Unavailable	0
City of Tallahassee	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Total	**$876-$1,220**	**$11**	**$1,100-$3,700**	**$409-$568**	**$2,396-$5,499**

* Excludes costs related to Crystal River Units 1 and 2.
** Excludes Capital Costs.
Source: TYSP Utility Data Responses

Modernization and Efficiency Improvements

Recently, several of Florida's utilities have taken advantage of high reserve margins and engaged in modernizations of existing plant sites. These projects involve removing existing generator units that may not be as economical to operate, such as oil-fired steam units, and reusing the 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 price lower than new construction.

The Commission has previously granted determinations of need for several conversions of oil-fired steam to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades sites. The Commission has also granted determinations of need for conversion of existing combustion turbines into combined cycle units, including the conversion of TECO's Polk Units 2 through 5 in 2012. DEF has also recently conducted a conversion of its Bartow plant, but this did not require a determination of need from the Commission.

Traditional Generation

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 investigated before considering new construction. Utilities should continue to explore potential conversion projects and report the feasibility and economic viability of each conversion in next year's TYSPs and before any need determination filing.

For some existing units, generation output can be improved by installing more advanced equipment. The Commission has previously granted determinations of need for uprates at existing nuclear units, resulting in an additional 440 MW in new capacity. FPL also plans improvements in several of its combined cycle generating units by upgrading the integrated combustion turbines.

Planned Retirements

This year's update of the utility's TYSPs includes a large number of retirements. The most notable of these is DEF's announcement of the retirement of Crystal River Unit 3 (CR3), one of only five nuclear plants within the state of Florida. CR3 had been offline for several years due to complications from a steam generator replacement project meant to expand the life of the unit beyond its initial 40 year planned life. As a going forward concern, this retirement reduces the fuel diversity of the existing generation fleet, further increasing dependence on natural gas which has served as the primary replacement fuel.

Table 12 below lists all planned retirements by TYSP Utilities of existing generating units over the planning period, totaling 4,144 MW, a majority of which is oil-fired steam generation. These is due to a combination of factors, with specific units retired due to the modernization of existing plants, the proposed EPA Rules discussed above, or the generating unit reaching the end of its design life.

Traditional Generation

Table 12: TYSP Utilities - Planned Unit Retirements

Utility	Generating Unit Name	Generator Type	Summer Capacity (MW)	Planned Retirement Date	Notes
Nuclear Units					
DEF**	Crystal River 3	Nuclear Steam	850	01/2013	
Oil-Fired Units					
FPL	Port Everglades 3 & 4	Oil Steam	761	01/2013	Modernization
FPL	Turkey Point 1 & 2	Oil Steam	788	01/2013	Synch. Condenser
DEF	Suwannee River 1 - 3	Oil Steam	129	06/2018	
DEF	Various	Oil Turbine	56	04/2016	
Coal-Fired Units					
DEF	Crystal River 1 & 2	Coal Steam	869	04/2016	EPA Rules Related
GPC	Scholz 1 & 2	Coal Steam	92	04/2015	EPA Rules Related
Gas-Fired Units					
FPL	Municipal Plant 2 & 5	Gas CC	44	01/2017	
FPL	Municipal Plant 1, 3, 4	Gas Steam	94	01/2014	
DEF	Various	Gas Turbine	129	06/2016	
GPC	Pea Ridge 1-3	Gas Turbine	12	12/2018	
GRU	Various	Gas Steam	98	10/2015*	
GRU	JR Kelly GT01-03	Gas Turbine	42	02/2018*	
TAL	Various	Gas Turbine	56	03/2015*	
TAL	Various	Gas Steam	124	12/2013*	
Total			**4,144**		

*Planned Retirement Date is for earliest unit retirement. Other units may retire later than indicated here
** Multiple Joint Owners for Crystal River 3. Primary owner listed here.

Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan

Reserve Margin Requirements

In order to maintain stability in the electric system, utilities must constantly adjust system output to match demand from moment to moment. As demand fluctuates, utilities must generate the precise amount of electrical power that will keep the system in balance while also performing periodic maintenance on its generating units. In addition, utilities must be prepared at any moment to meet unforeseen circumstances, such as extreme weather events or unit outages. Therefore, each utility must maintain a certain amount of "extra" or reserve capacity in the event that demand rises above or supply drops below forecasted levels. This additional amount of generating capacity is expressed as a percentage of firm demand and is referred to as the reserve margin.

Reserve margins in Florida typically remain well above the FRCC minimum of 15 percent for most of the year, and usually will only approach minimum levels in the summer peak season when air conditioning loads are at their highest levels. The higher margins during winter peak seasons are also due to the fact that generating units can operate at a higher capacity in colder temperatures. The three largest IOUs, FPL, DEF, and TECO, were party to a stipulation approved by the Commission setting a 20 percent reserve margin planning criterion.

The values in Figure 11 below include both supply-side and demand-side contributions, and shows that planning is mostly controlled by summer peak demand. It should be noted that the figure below is for the State of Florida, and therefore contains generating capacity outside of the FRCC region.

Figure 11: State of Florida - Seasonal Reserve Margin (Summer & Winter)

Source: 2013 FRCC Regional Load & Resource Plan

Role of Demand Side Management in Reserve Margin

It should be noted that the reserve margin figures above are calculated using the net firm system demand for the diagonal shaded value, which assumes full use of interruptible load and load management devices to reduce peak demand, while the reserve margin which only includes generation and conservation is the solid value. Participation in interruptible rates and load management programs are voluntary, for which incentives are provided in the form of lower rates or credits paid to the participant. As shown in Figure 11 above, the state as a whole has sufficient generation capacity planned throughout a majority of the period to meet the minimum reserve margin of 15 percent without relying on demand response. As noted previously, these customers have not typically been activated during periods of peak demand.

New Generation Resources

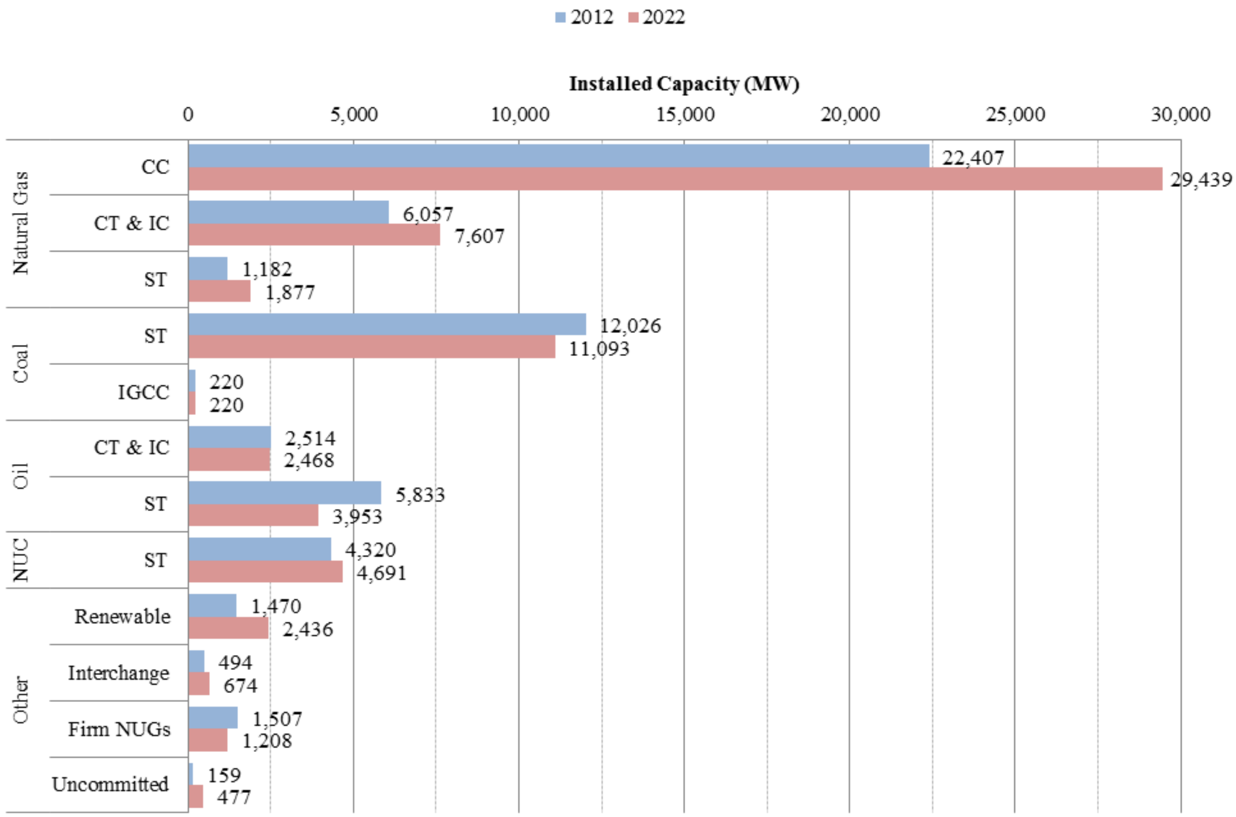
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant,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

Figure 12 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 12 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2013 Ten-Year Site Plans.

Traditional Generation

Figure 12: State of Florida - Installed Capacity (Existing & Projected)



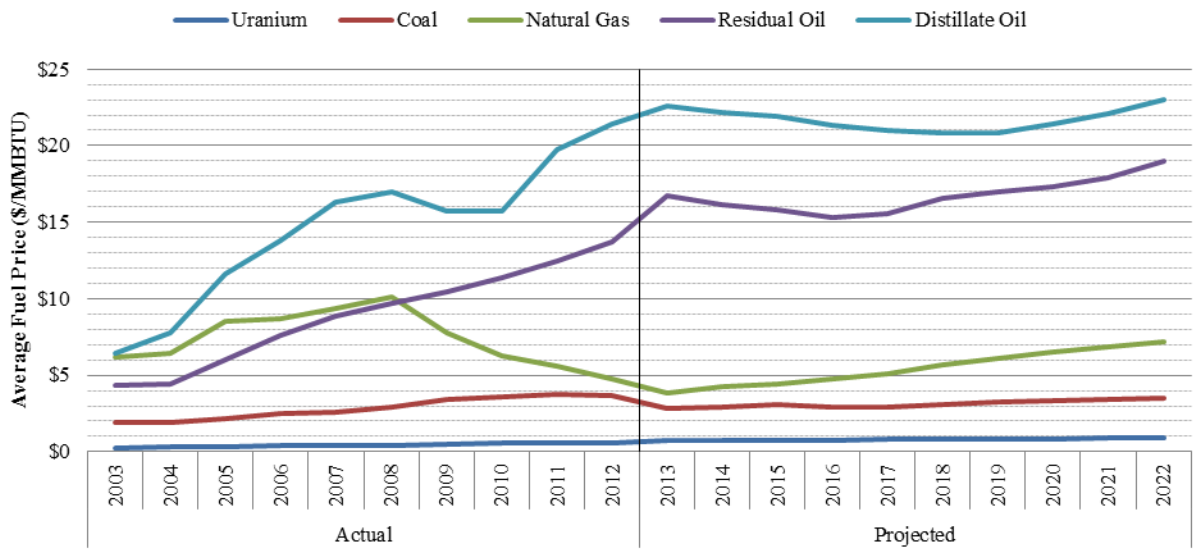
Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan, 2013 TYSP Utilities Data Responses

Fuel Price Forecasts

Fuel price forecast is the primary factor affecting the type of generating unit added by an electric utility. In general, the capital cost of a generating unit is inversely proportional to the cost of the fuel used to generate electricity from that unit. Historically, when the forecasted price difference between coal or nuclear and natural gas was small, the addition of a natural gas unit became the more attractive option. As the fuel price gap widened, a coal-fired or nuclear unit would normally be the more likely choice.

From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecasted. This disparity led to concern regarding escalating customer bills and an expectation that natural gas prices would continue to be high and extremely volatile. As a result, Florida's utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Due to concerns regarding potential future environmental regulations and other projected costs, coal-fired generation was not selected. However, as Figure 13 shows, the price of natural gas began to return to more historic levels after peaking in 2008, and has declined in the years since. Forecasts predict that gas prices will increase at a steady rate throughout the planning horizon. This trend has encouraged utilities to switch units to be capable of burning natural gas, either as a starter fuel, supplemental fuel, or the primary fuel by changing the fuel type of a generating unit entirely.

Figure 13: TYSP Utilities - Fuel Prices (History & Forecast)

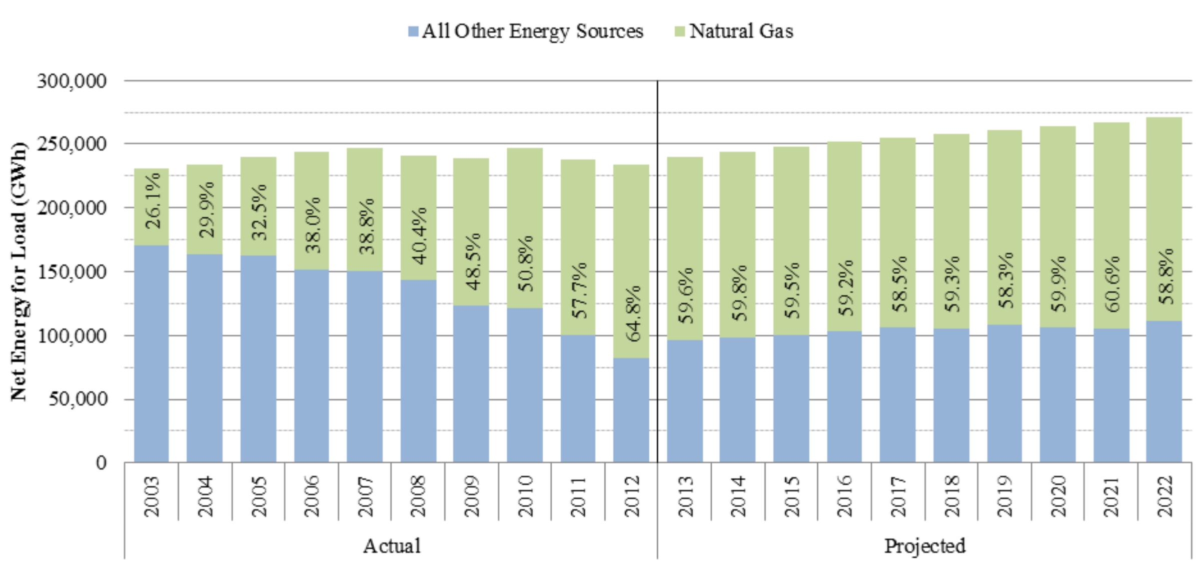


Source: TYSP Utilities Data Responses

Fuel Diversity

Natural gas has risen to become one of the dominant fuels in the state in the last ten years, displacing coal, and in 2012 generated more net energy for load than all other fuels combined in Florida. As Figure 14 shows, natural gas now makes up greater than 64.8 percent of electric energy consumed in Florida. Natural gas usage is anticipated to decline somewhat, remaining at approximately 60 percent throughout the planning period, ending up at 58.8 percent by 2022.

Figure 14: State of Florida - Natural Gas Usage (History & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

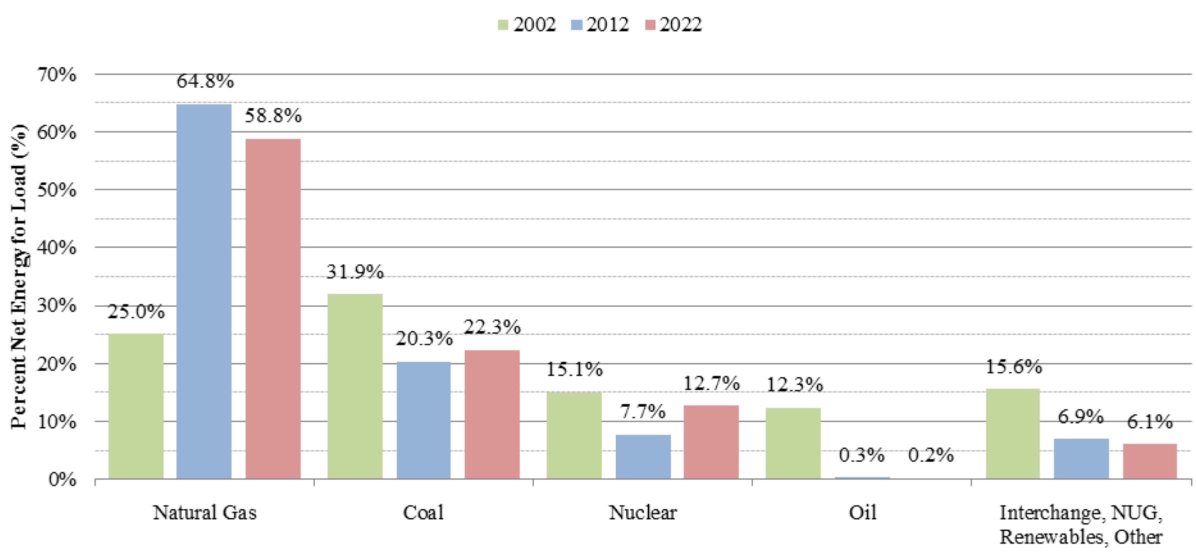
Traditional Generation

Combustion turbine technology is more efficient when used in a combined cycle mode, in which waste heat is recovered to generate steam, than steam generation alone. This gives natural gas a technological edge above its normal fuel price, so less fuel is required per unit of electricity generated. Because of this, despite coal having a lower price per unit energy, it is typically dispatched after natural gas based on current and projected fuel prices. As this gap widens again towards the end of the period, some increases in coal-fired generation are anticipated.

Utility plans for a balanced fuel system have historically been highly dependent upon the accuracy of long-term fuel price forecasts, mostly due to the long lead times required for coal and especially nuclear generators. However, in recent years the options available to utilities for the addition of supply-side generation have been limited, and this situation seems unlikely to change at this time. Utilities will be faced with selecting technologies for new generation that will either continue to increase the already very high percentage of natural gas resources, or attempting to obtain approval for solid fuel resources that may have a negative near term rate impact.

The anticipated decline in natural gas consumption over the planning period is the result of increased nuclear generation from FPL's uprates, which had many of their units off-line in 2012, and a slight increase in contribution to NEL from coal-fired generation. Nuclear generation is anticipated to increase at the end of the planning period, with the addition of Turkey Point 6 in the middle of 2022, to be followed the next year, outside of this planning period, by Turkey Point 7 in 2023. Figure 15 below illustrates the anticipated contribution by natural gas, coal, nuclear, oil, and all other sources, including interchange, non-utility generators, and renewables.

Figure 15: State of Florida - Fuel Diversity (History & Forecast)



Source: 2004 & 2013 FRCC Regional Load & Resource Plan

Compared to other states, Florida's usage of natural gas for electric generation is high when compared to total natural gas usage. At the TYSP Workshop, the FRCC provided data from the Energy Information Administration (EIA) that shows that in 2011 Florida used approximately 86 percent of natural gas consumed in the state for electric generation, the highest rate in the nation. Natural gas is typically not used in end-user heating, with a majority of Florida's residential heating from electrical generation.

Table 13: FRCC - Ten Largest States for Natural Gas Consumption (2011 Data)

State	Total Annual Natural Gas Consumption (Bcf)	Annual NG Consumption for Electric Generation (Bcf)	Total Annual Marketed Natural Gas Production (Bcf)	Total Miles of Natural Gas Pipeline	Total Storage Capacity (Bcf)
Texas	3,646	1,555	7,113	58,588	812
California	2,153	651	250	11,770	571
Louisiana	1,398	462	3,029	18,900	690
Florida	**1,218**	**1,050**	**15**	**4,971**	**0**
New York	1,217	427	31	5,018	246
Illinois	987	50	2	11,911	997
Pennsylvania	*963*	304	1,311	8,680	777
Ohio	*820*	93	79	7,670	580
Michigan	*776*	100	138	9,722	1,075
New Jersey	*661*	188	0	1,520	0
Total US	***24,385***	**7,884**	**24,036**	**305,954**	**8,849**
Florida as % of Total	***5.0%***	**13.3%**	**0.06%**	**1.6%**	**0%**

Source: FRCC 2013 TYSP Workshop Presentation

As shown above, Florida has very little production and no gas storage capacity, yet is the fourth largest overall consumer of natural gas. Because of geographic constraints, Florida will most likely continue to rely on out of state production and storage to satisfy the growing electric demands in the state.

Coal generation, beyond the reduction in dispatch due to the cost-competitiveness of natural gas as a baseload fuel, faces challenges relating to new environmental compliance requirements. As discussed above, new EPA regulations will potentially require installation of new environmental controls, which could lead to the retirement of units if it is deemed uneconomic to upgrade its emission control equipment.

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatile fuel price fluctuations, it is important that utilities have the greatest possible level of flexibility in their generation fuel source mix. Although the Commission has cited the growing lack of fuel diversity within the State of Florida as a major strategic concern for the past several years, natural gas is anticipated to remain the dominant fuel over the planning horizon. Excluding renewables and one nuclear unit, all new generation facilities planned within the State of Florida over the ten-year period are natural gas-fired units.

Projected New Units by Fuel Type

In the last ten years, almost all capacity additions to Florida's electric system use natural gas as the primary fuel. Coal units that were planned have been cancelled, and a majority of new nuclear units that have been approved have been delayed beyond the planning horizon. Gas fired units have almost exclusively been selected in recent years due to higher thermal efficiencies, lower capital costs, short periods for permitting and construction, and sometimes the smaller land areas required. With the recent decrease in fuel prices due to unconventional natural gas production using hydraulic fracturing, natural gas is the favored fuel for all traditional generating units with the exception of new nuclear units.

Currently, other than approximately 966 MW of renewable generation and 1,220 MW in uprates and new nuclear units, all of the additional generation planned for the next ten years will use natural gas as a fuel source.

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Florida's utilities project an expansion of nuclear power in the state through uprates at existing nuclear power plants, and the construction of two new nuclear units. Table 14 below shows new nuclear capacity anticipated in the planning period. The Commission previously approved uprates for all existing nuclear units in Florida. The only remaining uprate to be completed is FPL's Turkey Point Unit 4, completed earlier this year. FPL also projects the first of its two new nuclear generating units to come online within the planning period, Turkey Point Unit 6. The second unit is anticipated to be in-service by 2023. DEF's 2012 TYSP included the return to service of an uprated CR3 in 2014. DEF's 2013 TYSP reflects the fact that CR3 has been retired and will not return to service.

Table 14: TYSP Utilities - Nuclear Unit Additions

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
FPL	Turkey Point 4 Uprate	120	01/2008	10/2008	03/2013
FPL	Turkey Point 6	1,100	04/2008	*	06/2022
Total Nuclear Additions		**1,220**			
* This units have not yet received PPSA Certification					

Source: 2013 TYSPs

Pursuant to a multi-party stipulation, DEF has elected to discontinue construction of its Levy Nuclear Plants. DEF will, however, continue its efforts to obtain a combined operating license from the Nuclear Regulatory Commission for the Levy Nuclear Project.

Natural Gas

With the exception of the aforementioned renewable and nuclear capacity, all remaining new generation comes in the form of natural gas fired combustion turbines or combined cycle units. Natural gas-fired combined cycles represent the most abundant type of generating capacity in the State of Florida, making up approximately 38.5 percent of installed capacity in 2012. Combustion turbines run in simple cycle mode represent the third most abundant type of generating capacity, behind only coal-fired steam generation. Because combustion turbines are not a form of steam generation unless part of a combined cycle system, they do not require siting under the PPSA. Table 15 below includes approximately 8,683 MW of natural gas-fired generation included in the 2013 TYSPs.

Table 15: TYSP Utilities - Natural Gas Unit Additions

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
Combined Cycle Units					
FPL	Cape Canaveral	1,210	09/2008	10/2009	06/2013
FPL	Riviera Beach	1,212	09/2008	11/2009	06/2014
FPL	Port Everglades	1,277	04/2012	03/2013	06/2016
DEF	Unnamed CC 1	1,189	*	*	06/2018
DEF	Unnamed CC 2	1,189	*	*	06/2020
TECO	Polk 2-5 CC Conversion	459	12/2012	*	01/2017
SEC	Unnamed CC 1	192	*	*	12/2020
SEC	Unnamed CC 2	192	*	*	12/2020
Combustion Turbine Units					
SEC	Unnamed CT 1	198	**	**	12/2019
TECO	Future CT	190	**	**	05/2020
TAL	Hopkins 5	46	**	**	05/2020
SEC	Unnamed CT 2 & 3	396	**	**	12/2020
SEC	Unnamed CT 4 - 7	792	**	**	12/2021
DEF	Unnamed CT	187	**	**	06/2022
Total Natural Gas Additions		**8,683**			

* These units have not yet received a Determination of Need and/or a PPSA Certification.
** These units are not regulated under the PPSA, and do not require a Determination of Need.
Source: TYSP Utilities Data Response

Power Plant Siting Act[8]

The Florida PSC is given exclusive jurisdiction by the Legislature, through the PPSA, to be the forum for determining the need for new electric power plants. Any proposed steam or solar generating unit of at least 75 MW requires certification under the Power Plant Siting Act.

Approximately 9,960 MW of new utility-owned generating units are planned to enter service over the next 10-year period, with 82 percent of that subject to the PPSA. A majority of

[8] Sections 403.501 through 403.518, F.S.

this portion new generation has already received a determination of need from the Commission. A total of 2,762 MW still requires certification, as shown in Table 16.

Table 16: State of Florida - Proposed Generation Requiring Commission Approval

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
DEF	Unnamed CC 1	1,189	06/2018
DEF	Unnamed CC 2	1,189	06/2020
SEC	Unnamed CC 1	192	12/2020
SEC	Unnamed CC 2	192	12/2020
Total Capacity		**2,762**	

Source: 2013 TYSPs

Transmission Capacity

As generation capacities increase, the transmission system must grow accordingly to maintain the capability of delivering the energy to the end user. 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 Transmission Line Siting Act (TLSA).[9] 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 for and the proposed starting and ending points for lines requiring TLSA certification. The Commission must issue a final order granting or denying a determination of need within 90 days of the petition filing. The proposed corridor route is determined by the DEP 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 the proposed line.

Table 17 below lists all proposed transmission lines in the 2013 TYSPs that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

Table 17: TYSP Utilities - Transmission Requiring TLSA Approval

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Certification Dates		Commercial In-Service Date
				Need Approved (Commission)	TLSA Certified	
DEF	Intercession City - Gifford	13	230	09/2007	01/2009	05/2013
FPL	Manatee - Bob White	30	230	08/2006	11/2008	12/2014
FPL	St. Johns - Pringle	25	230	05/2005	04/2006	12/2017

Source: TYSP Utilities Data Responses

[9] Sections 403.52 through 403.5365, F.S.

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is the state's largest electric utility. The utility's service territory is within the FRCC region, and is primarily in southern Florida and along the east coast. As FPL is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

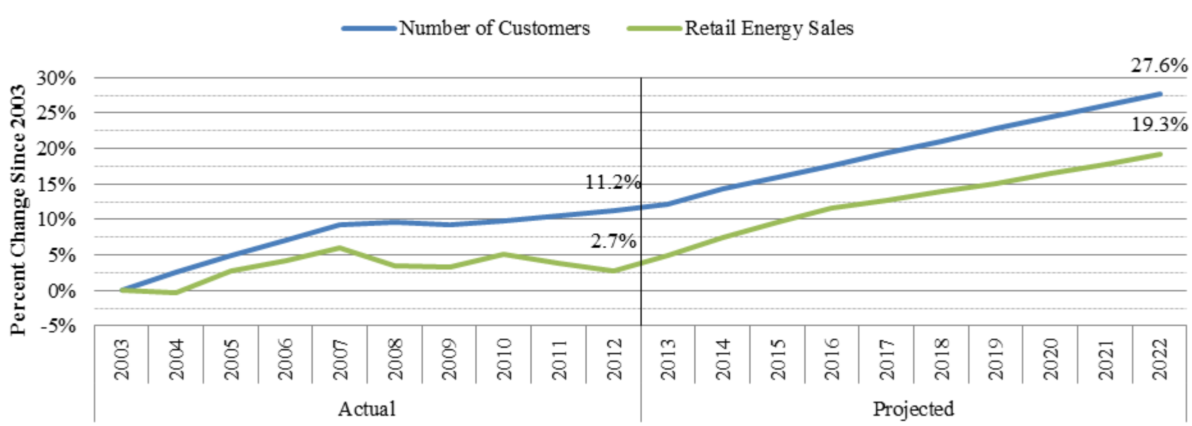
In 2012, FPL had approximately 4,572,800 customers, with annual retail energy sales of 101,678 GWh, or approximately 47.3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 16.

Figure 16: FPL - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 17 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, FPL has increased/decreased its total number of customers by 11.2 percent, while increasing retail energy sales by 2.7 percent. The company forecasts continued positive growth for all years of the planning period, with retail energy sales exceeding the historic 2007 peak by 2014.

Figure 17: FPL - Customer and Retail Energy Sale Growth Since 2003



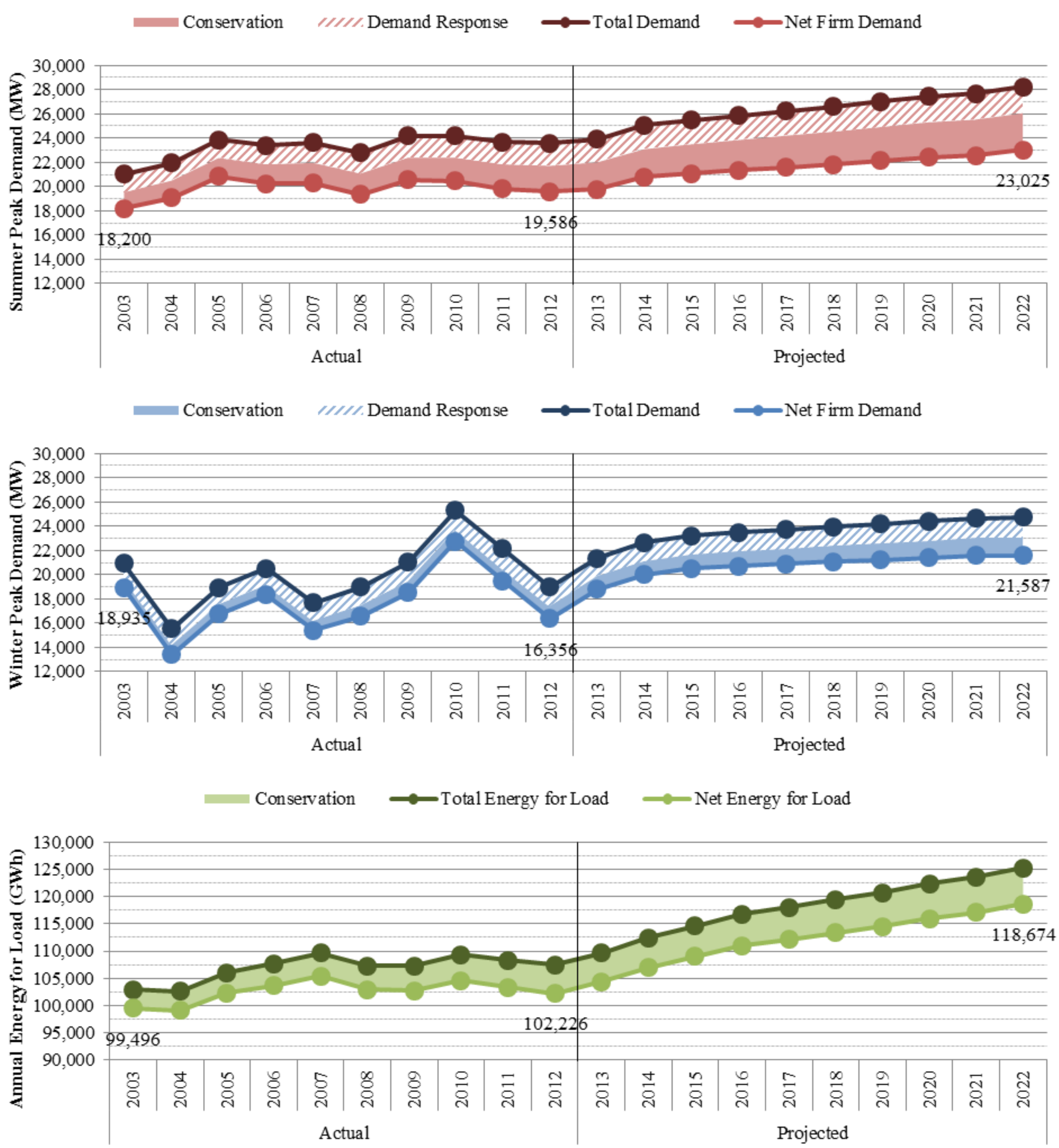
Source: 2013 TYSP Schedule 2

Florida Power & Light (FPL)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 18 show FPL's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but demand response was not activated during the historic seasonal peak demand hours, excluding the winters of 2010 and 2011.

Figure 18: FPL - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



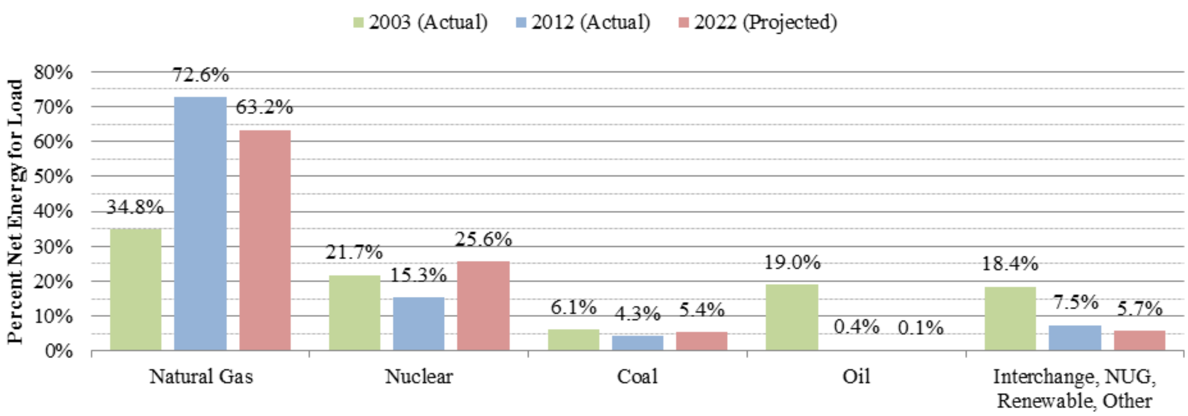
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 19 shows FPL's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. FPL's primary generation fuel is natural gas, which has increased from 34.8 percent of system energy in 2003, to 72.6 percent in 2012. A portion of this increase is due to long-term outages of several nuclear units on FPL's system for uprates during 2012, with nuclear representing FPL's next highest fuel usage. The return to service of the uprated nuclear units will slightly decrease FPL's natural gas usage, estimated at 66.1 percent in 2013. The trend of natural gas being the primary system fuel will continue, with another decrease in usage, to 63.2 percent in 2022, due to an increase in nuclear generation with the addition of Turkey Point 6 for a portion of the year. Natural gas usage is anticipated to decline again in 2023 with a full year of operation of Turkey Point 6 and a partial year for Turkey Point 7.

Figure 19: FPL - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

FPL's 2013 TYSP includes five planned generation additions, including three combined cycle units, a nuclear uprate, and a new nuclear unit. A second new nuclear unit, Turkey Point 7, is planned in 2023, outside of the 2013 TYSP planning period. The planned units are detailed below in Table 18. This is consistent with the company's 2012 TYSP, featuring no new generating units. The previous TYSP also included the uprates completed in 2012 to FPL's other three nuclear units.

Table 18: FPL - Planned Generation Additions

Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Cape Canaveral Energy Center	Combined Cycle	1,210	06/2013	Approved
Riviera Beach Energy Center	Combined Cycle	1,212	06/2014	Approved
Port Everglades Energy Center	Combined Cycle	1,277	06/2016	Approved
Nuclear Units				
Turkey Point Unit 4 Uprate	Steam Turbine	120*	03/2013	Approved
Turkey Point Unit 6	Steam Turbine	1,100	06/2022	Pending

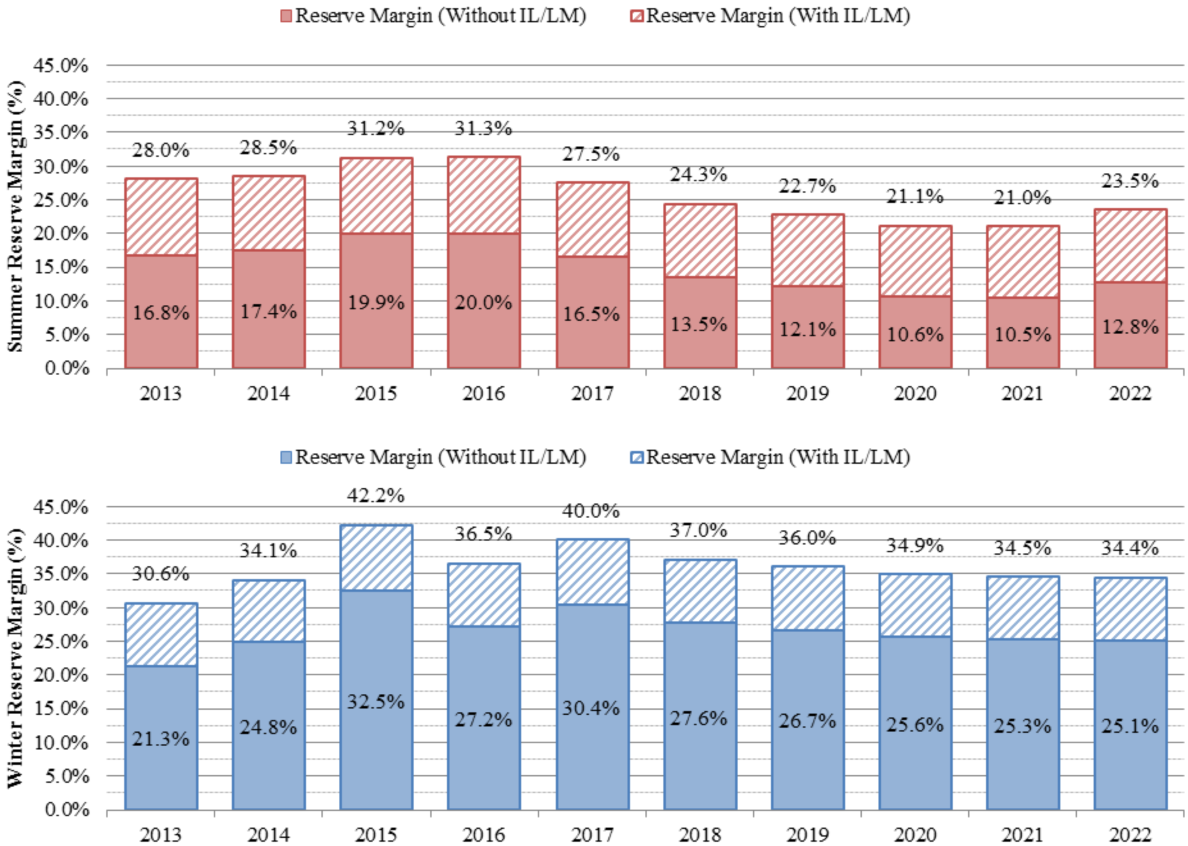
*This capacity represents the uprate only, not the full capacity of the generating unit
Source: 2013 TYSP Schedule 8

Florida Power & Light (FPL)

Reserve Margin

FPL maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 20 displays the forecast planning reserve margin for FPL through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, FPL is a summer peaking utility.

Figure 20: FPL - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Duke Energy Florida, Inc. (DEF)

DEF is an investor-owned utility, and Florida's second largest TYSP utility. The utility's service territory is within the FRCC region, and is primarily located in central and west central Florida. The company's TYSP was filed under its previous business name, Progress Energy Florida, Inc. (PEF). As DEF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

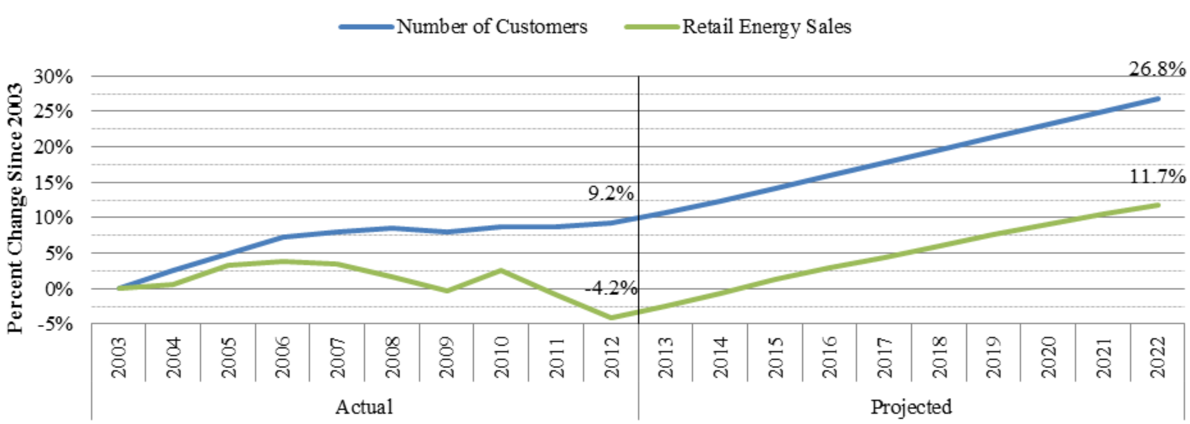
In 2012, DEF had approximately 1,624,400 customers, with annual retail energy sales of 33,135 GWh, or approximately 17.6 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 21.

Figure 21: DEF - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 22 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, DEF has increased its total number of customers by 9.2 percent, while retail energy sales have declined by 4.2 percent. The company forecasts positive growth for all years of the planning period, with retail energy sales exceeding the historic 2006 peak by 2017.

Figure 22: DEF - Customer and Retail Energy Sale Growth Since 2003



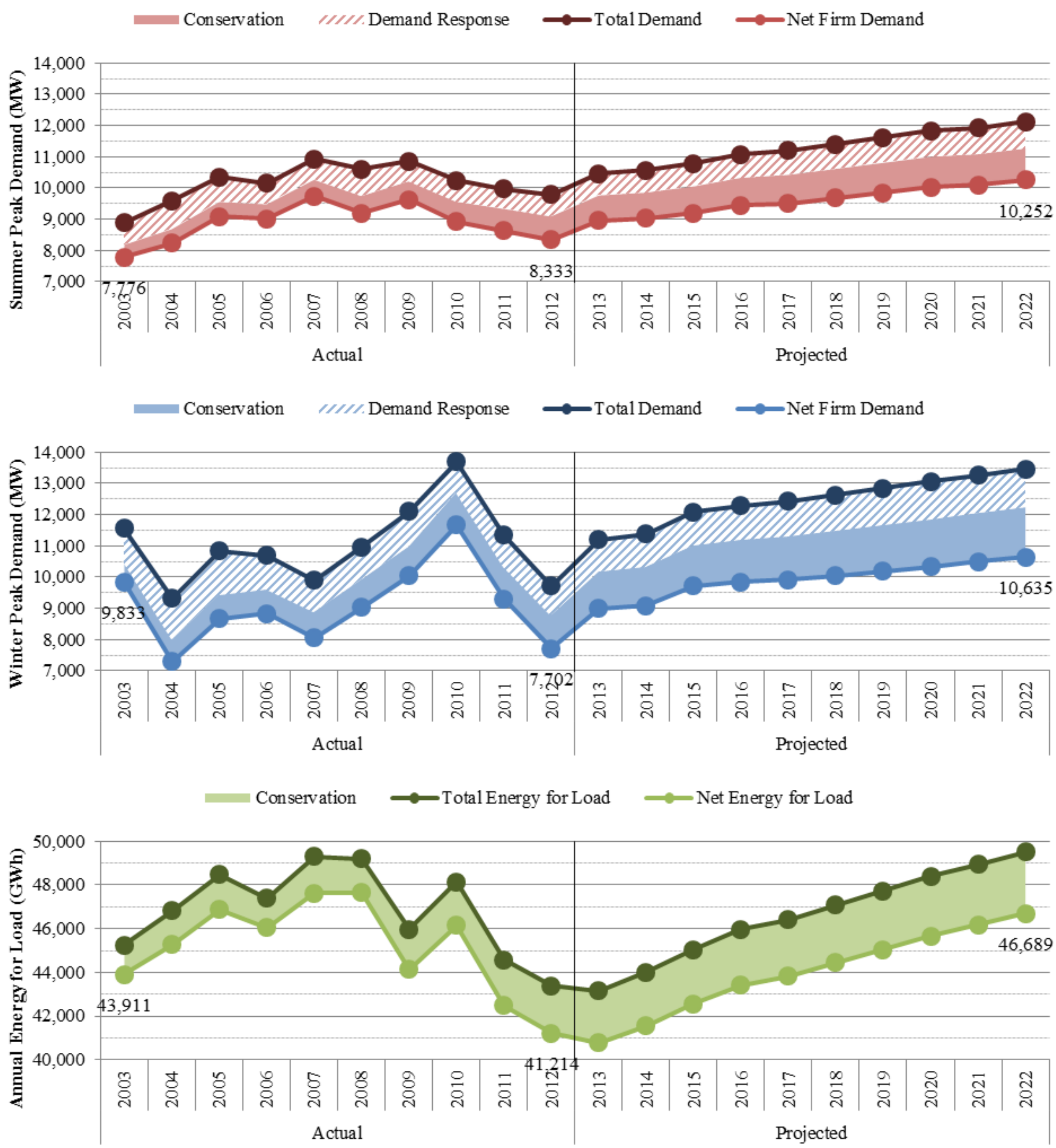
Source: 2013 TYSP Schedule 2

Duke Energy Florida (DEF)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 23 show DEF's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but generally these programs have not been activated during summer peak periods. Demand response was utilized during seasonal peak demand periods in the summer of 2005 and winters of 2003, 2006 through 2008, and 2010.

Figure 23: DEF - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



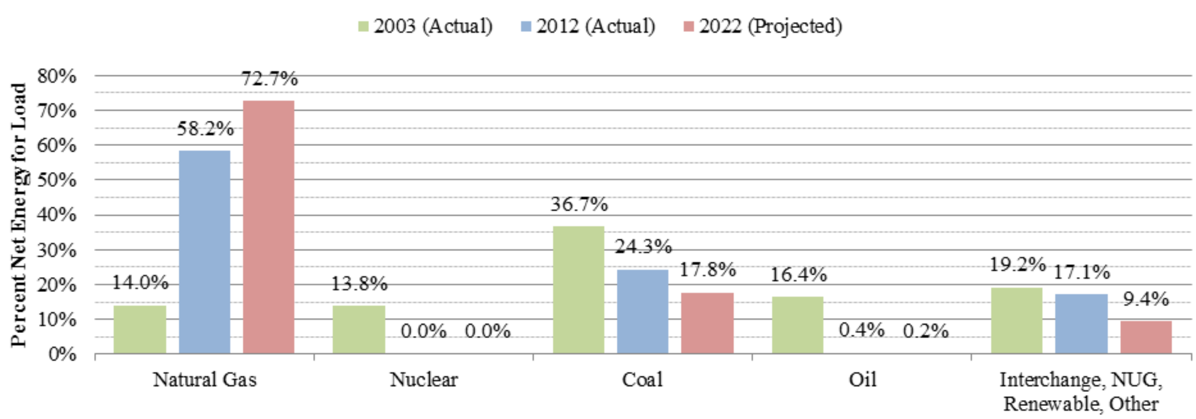
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 24 shows DEF's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. DEF's primary generation fuel is natural gas, which has increased from 14 percent of system energy in 2003, to 58.2 percent in 2012. A portion of this increase is due to the retirement of the Crystal River 3 nuclear unit, which previously provided over ten percent of system energy. Coal has the second highest fuel usage, but is anticipated to decline and be replaced by natural gas over the planning period. Purchased power makes up a sizeable portion of DEF's system energy, at 17.1 percent in 2012, with a peak projected in 2017 at 24 percent of system energy. Purchased power is anticipated to decline while natural gas increases with the addition of new natural gas-fired generation discussed below.

Figure 24: DEF - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

DEF's 2013 TYSP includes three planned generation additions, two combined cycle units and a combustion turbine. All units are unsited at this time. The planned units are detailed below in Table 19. This represents an increase from the company's 2012 TYSP in both number of generating units and total capacity. The previous TYSP had projected a return to service of an uprated Crystal River 3 by the end of 2014 and a single combined cycle unit in 2019.

Table 19: DEF - Planned Generation Additions

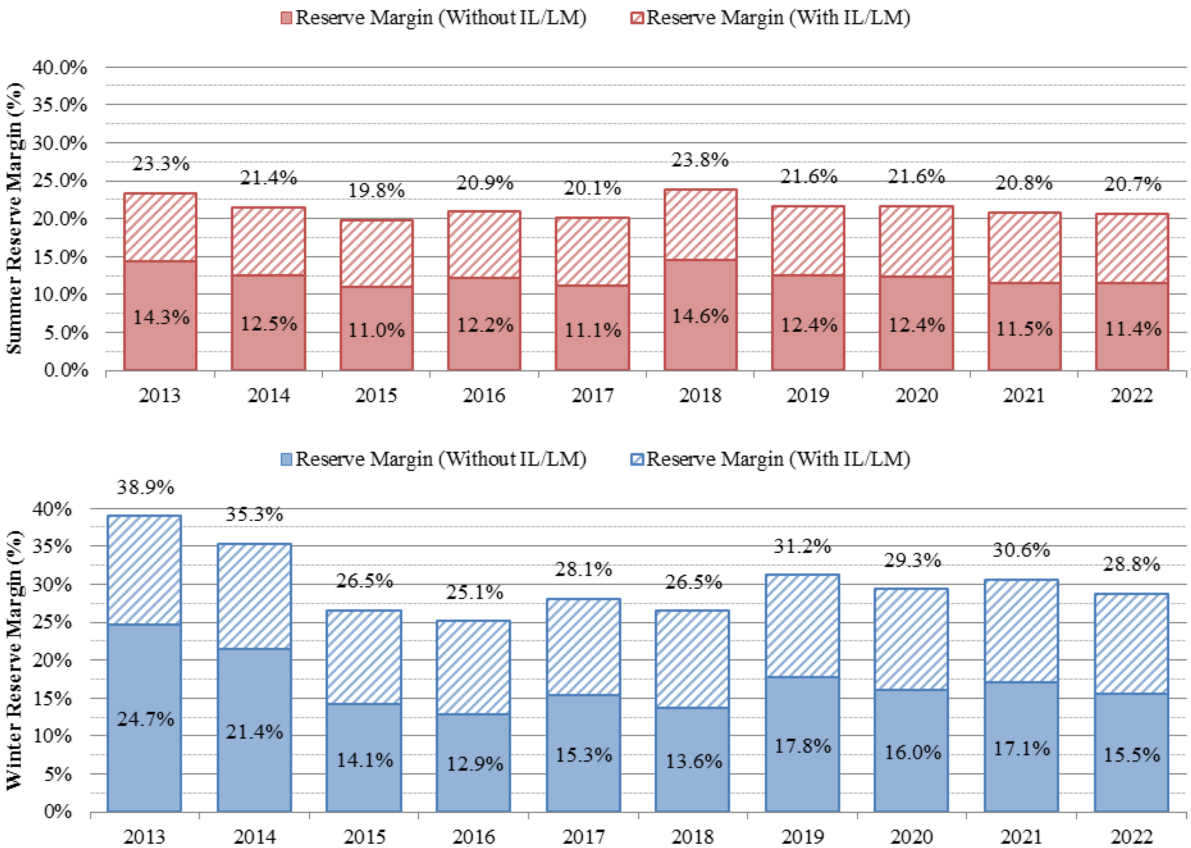
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Unnamed CC 1	Combined Cycle	1,189	06/2018	Required
Unnamed CC 2	Combined Cycle	1,189	06/2020	Required
Unnamed CT 1	Combustion Turbine	187	06/2022	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

DEF maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 25 displays the forecast planning reserve margin for DEF through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, DEF is a summer peaking utility.

Figure 25: DEF - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Due to the retirement of CR3, combined with the potential retirement of oil and coal-fired units totaling over 1,000 MWs due to potential EPA emissions rules, DEF will require a large amount of firm capacity to meet customer demand on a fairly short basis. While DEF projects construction of several generating units within the planning period, the earliest is anticipated to enter service in 2018, after any potential EPA related retirements. Therefore, DEF will require firm purchased power in the interim, especially for summer peaks. The company has issued two requests for proposals, seeking power both from within and outside Florida, and is in the process of negotiating with suppliers. It appears at this time that there is sufficient capacity available from other parties to provide for the required firm capacity purchases. The Commission will continue to monitor DEF's efforts to secure firm capacity for its customers.

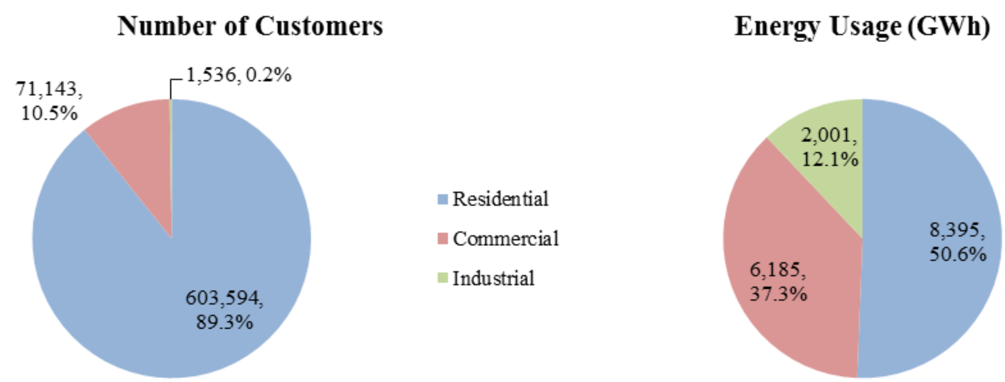
Tampa Electric Company (TECO)

TECO is an investor-owned electric utility, and Florida's third largest TYSP utility. The utility's service territory is within the FRCC region, and consists primarily of the Tampa metropolitan area. As TECO is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

In 2012, TECO had approximately 676,300 customers, with annual retail energy sales of 16,582 GWh, or approximately 8.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 26.

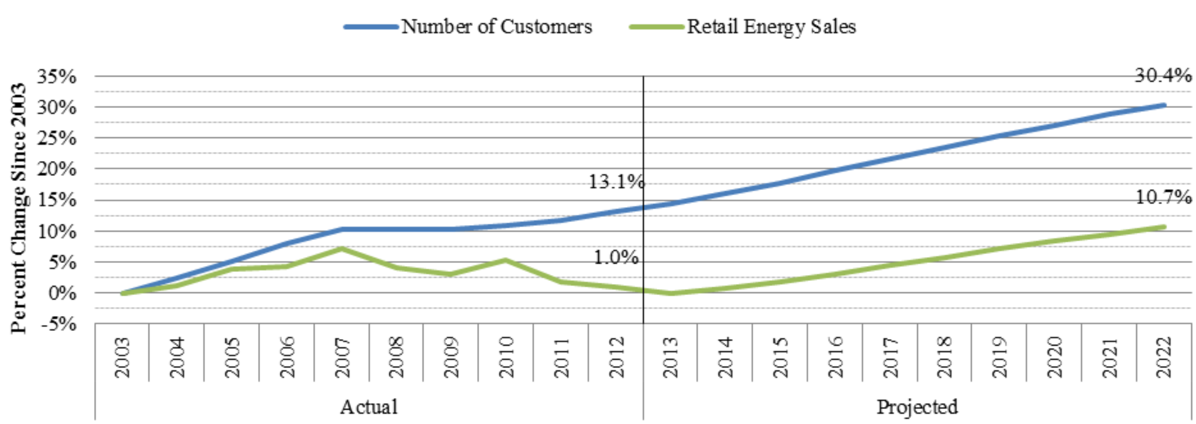
Figure 26: TECO - Number of Customers and Energy Usage by Class



Source: 2013 TYSP Schedule 2

Figure 27 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, TECO has increased its total number of customers by 13.1 percent, while increasing retail energy sales by 1.0 percent. The company forecasts continued positive growth most years of the planning period, with retail energy sales exceeding the historic 2007 peak by 2020.

Figure 27: TECO - Customer and Retail Energy Sale Growth Since 2003



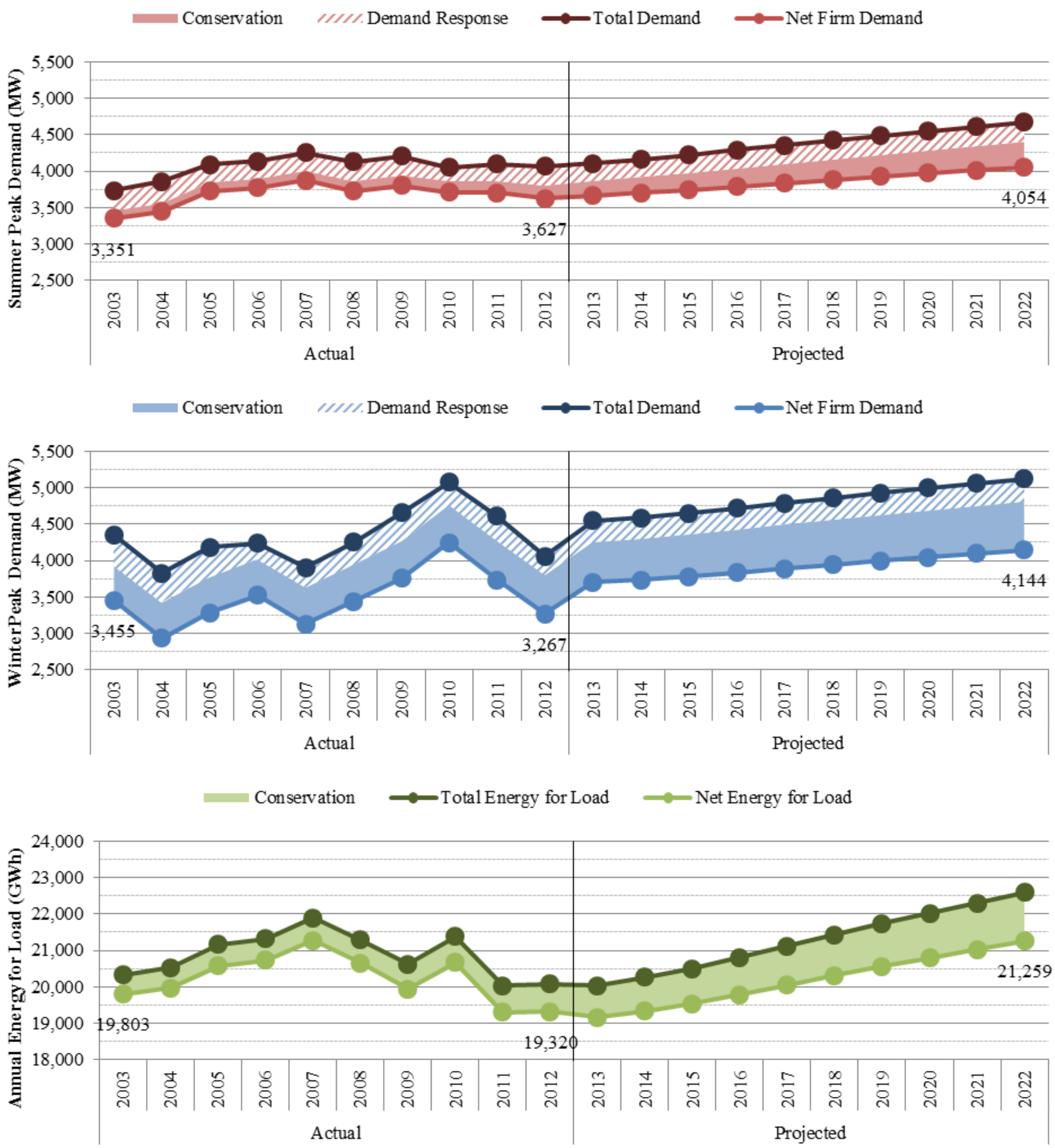
Source: 2013 TYSP Schedule 2

Tampa Electric Company (TECO)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 28 show TECO's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but generally these programs have not been activated, excluding three summer peaks, in 2005, 2007, and 2009.

Figure 28: TECO - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



Source: 2013 TYSP Schedule 3

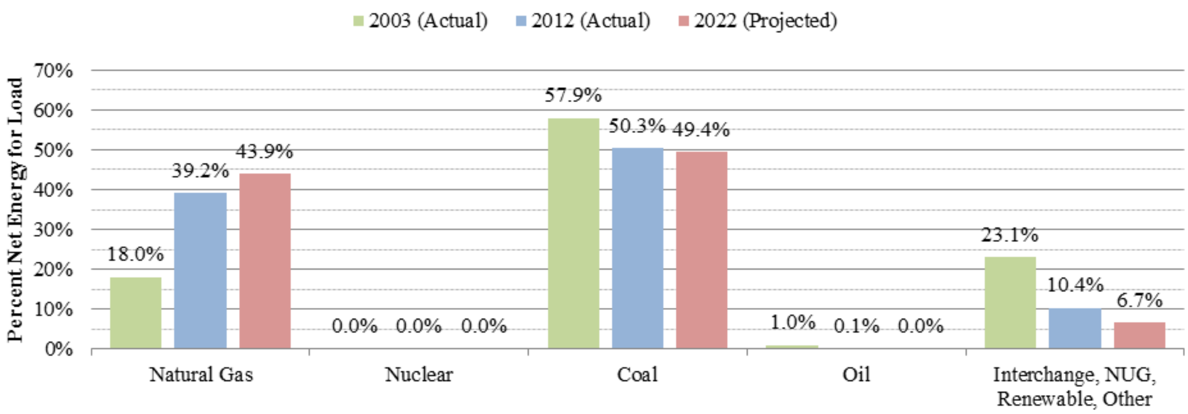
Tampa Electric Company (TECO)

Generation Resources

Fuel Diversity

Figure 29 shows TECO's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. TECO's primary generation fuel is coal, one of only two utilities in the state that relied upon the solid fuel over natural gas in 2012, with 50.3 percent of system energy generated by coal. Coal usage has declined however, primarily with the increase of natural gas, which is the next highest fuel for TECO's system energy. Natural gas has risen to 39.2 percent of system energy in 2012, up from only 18.0 percent in 2003. Coal is anticipated to remain the main system fuel throughout the planning period, making up 49.4 percent in 2022, although natural gas is projected to replace purchased power and increase its share of system energy to 43.9 percent in 2022.

Figure 29: TECO - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

TECO's 2013 TYSP includes two planned generation additions. The first is a modernization of their existing Polk plant site by converting the existing combustion turbines into a combined cycle unit. The second is a combustion turbine to be sited somewhere in Hillsborough County. These units are described below in Table 20. This is consistent with the company's 2012 TYSP, which included similar generating units. The primary change is the increase in capacity and one year delay in the in-service date of the planned combustion turbine.

Table 20: TECO - Planned Generation Additions

Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Polk 2-5 Conversion	Combined Cycle	459	01/2017	Pending
Future CT 1	Combustion Turbine	190	05/2020	N/A

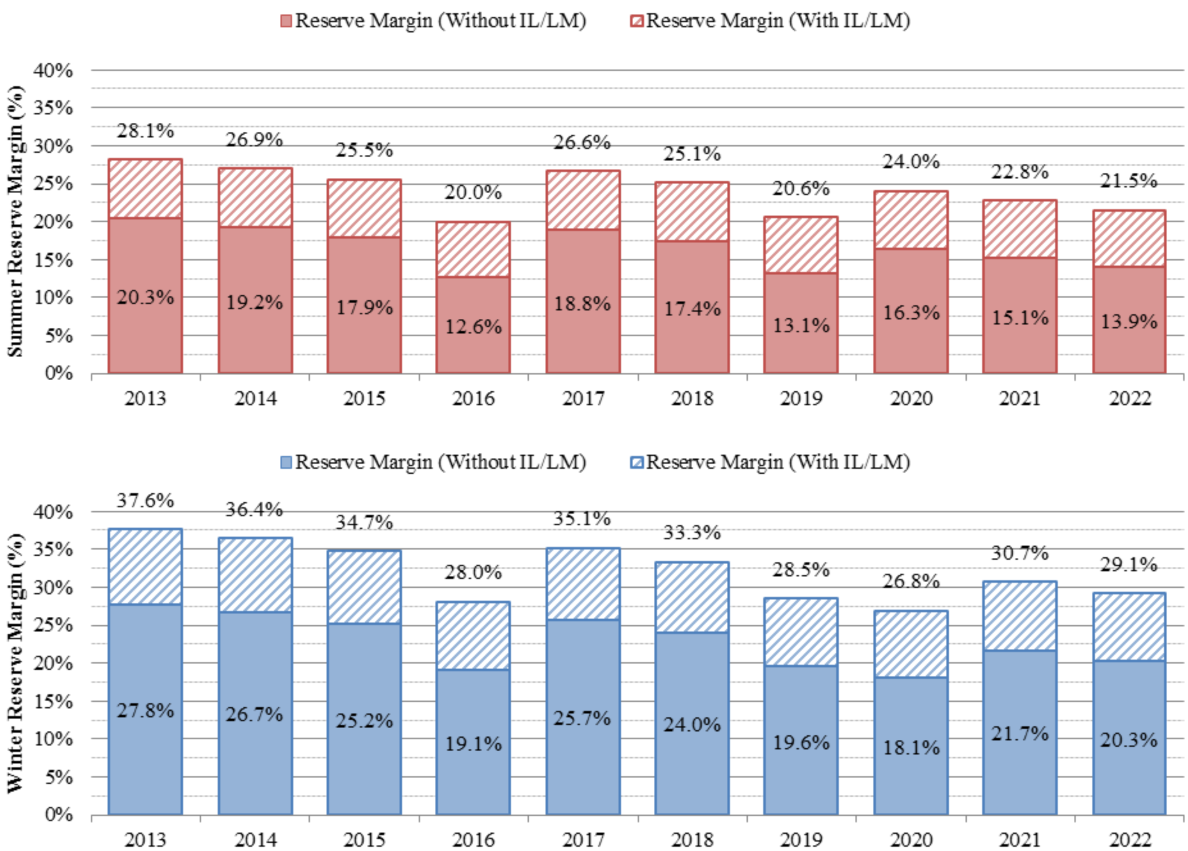
*Represents additional steam capacity from conversion, not including the original CT units.
Source: 2013 TYSP Schedule 8

Tampa Electric Company (TECO)

Reserve Margin

TECO maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 30 displays the forecast planning reserve margin for TECO through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, TECO is generally a winter-peaking utility, during certain periods summer peak demand can be of greater concern. TECO also maintains a minimum supply-side contribution to its reserve margin, set at 7 percent, which it exceeds in all years of the planning period.

Figure 30: TECO - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Gulf Power Company (GPC)

GPC is the smallest investor-owned generating utility, and the sixth largest TYSP utility. The utility's service territory includes western Florida. GPC is a member of the Southern Company electric system and has the SERC as its regional reliability entity. Because GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by the GPC units is consumed in Florida. As GPC is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

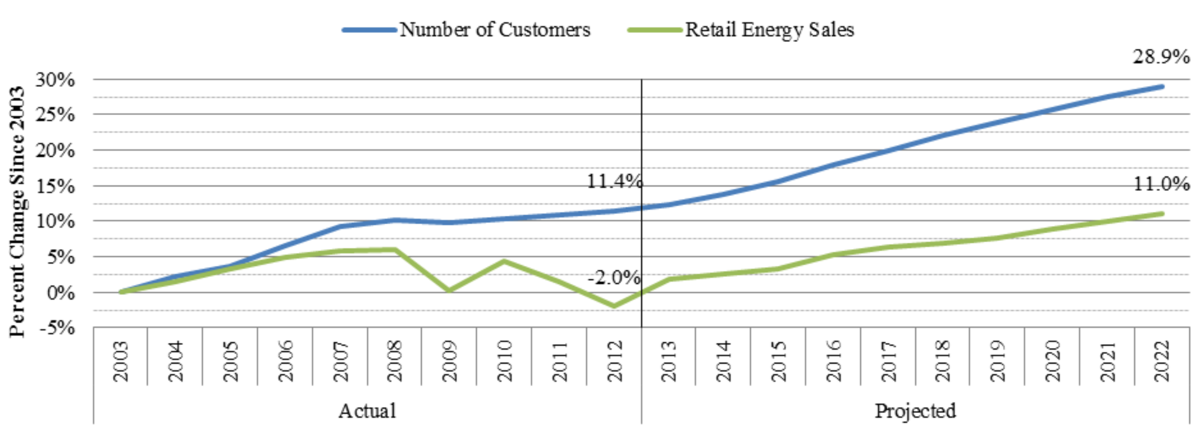
In 2012, GPC had approximately 433,900 customers, with annual retail energy sales of 10,637 GWh, or approximately 4.9 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 31.

Figure 31: GPC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 32 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, GPC has increased its number of customers by 11.4 percent, though retail energy sales have declined 2.0 percent. The company forecasts continued positive growth for all of the planning period, with retail energy sales exceeding the historic 2008 peak by 2017.

Figure 32: GPC - Customer and Retail Energy Sale Growth Since 2003



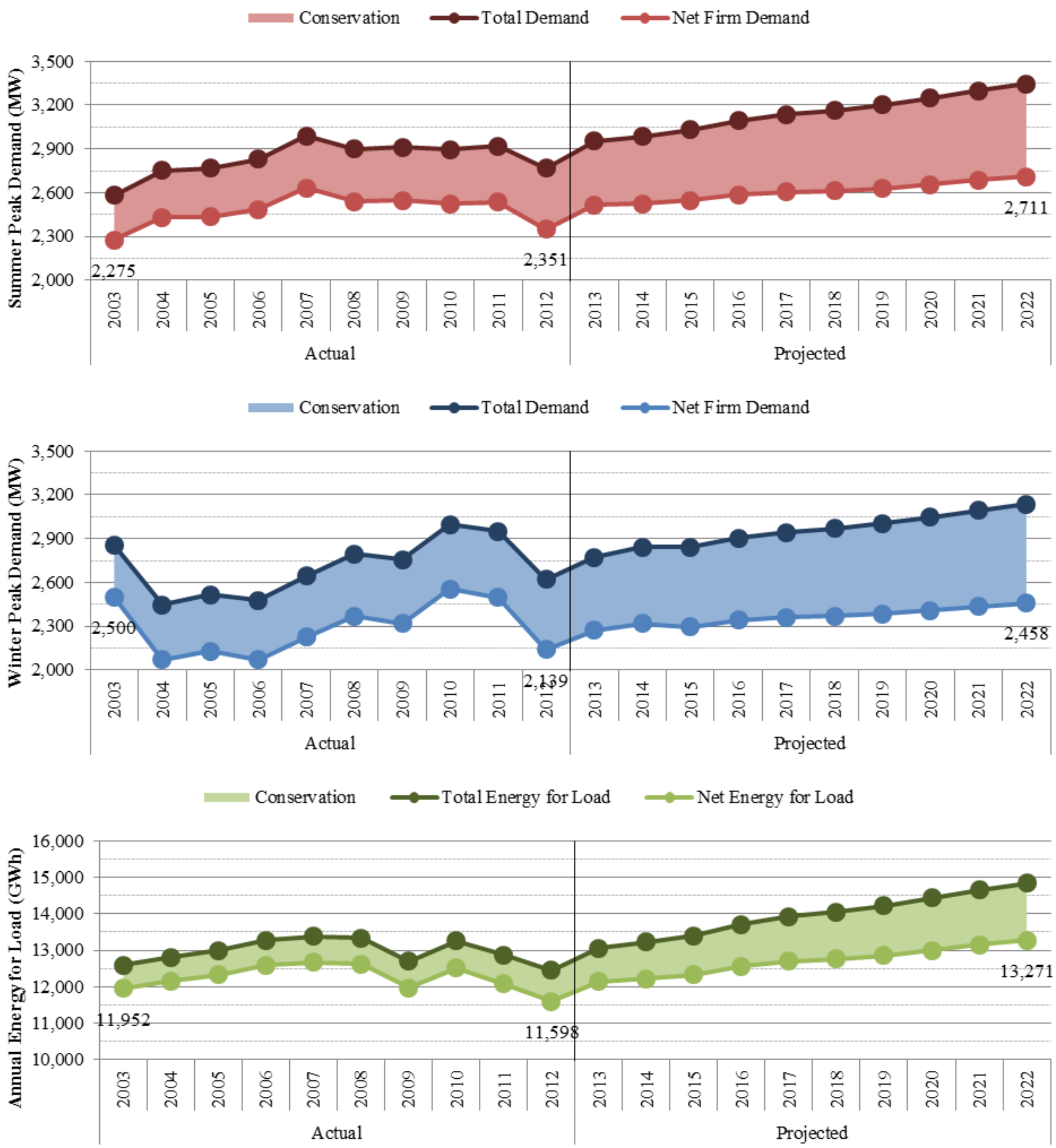
Source: 2013 TYSP Schedule 2

Gulf Power Company (GPC)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 33 show GPC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. GPC does not currently include any demand response in its forecasts.

Figure 33: GPC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



Source: 2013 TYSP Schedule 3

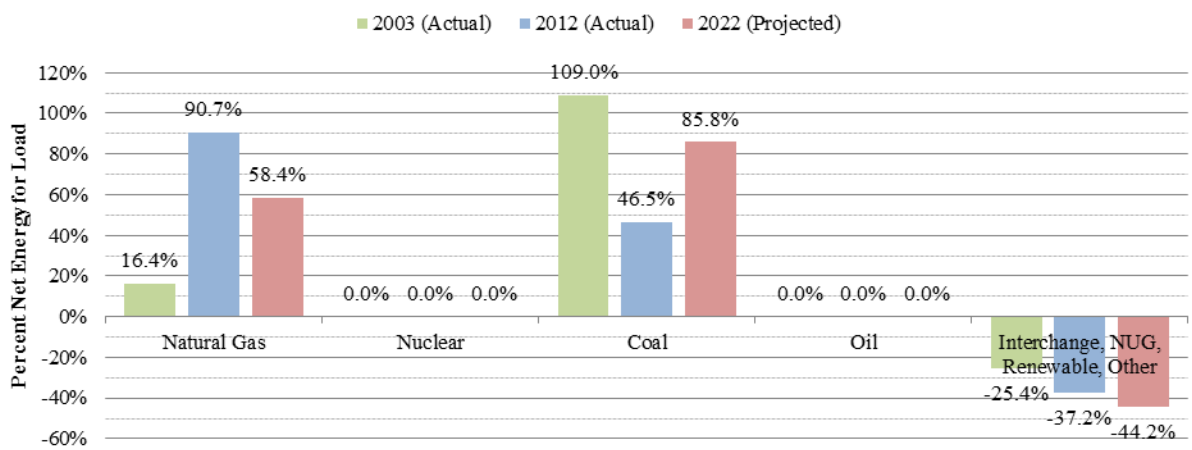
Gulf Power Company (GPC)

Generation Resources

Fuel Diversity

Figure 34 shows GPC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. GPC is a net energy exporter, and as a result produces more energy than its system consumes each year, with exports planned to increase over the planning period. GPC's primary fuel in 2012 was natural gas, at 90.7 percent of system energy, which displaced coal for the first time in the past ten years. Coal has declined from producing 109 percent of system energy in 2003, to only 46.5 percent in 2012. By the end of the planning period, GPC forecasts that coal will once again become the dominant system fuel, at 85.8 percent, with natural gas still contributing over half of system energy, at 58.4 percent.

Figure 34: GPC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

GPC's 2013 TYSP included a single generation addition at their existing Perdido landfill gas site in Escambia County. This is an increase from the company's 2012 TYSP, which included no new generating units.

Table 21

Table 21: GPC - Planned Generation Additions

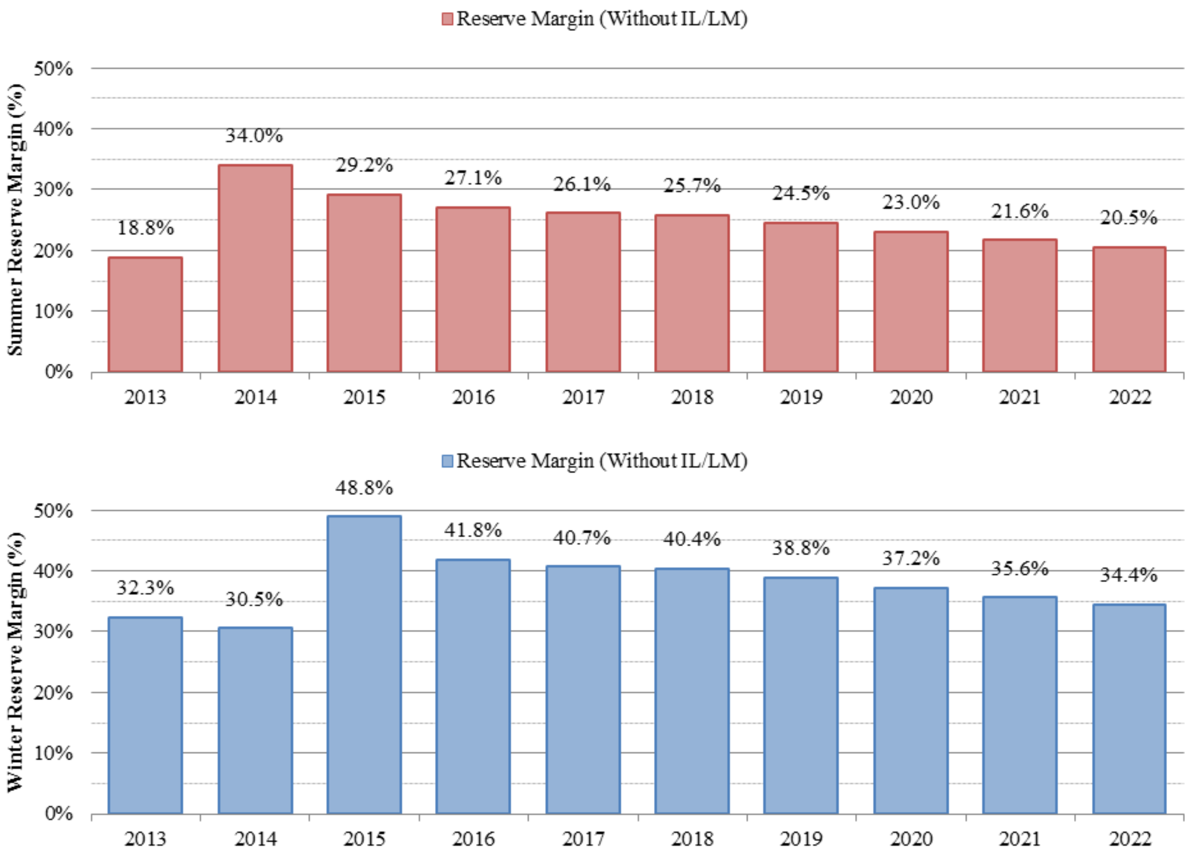
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Renewable Units				
Perdido 3	Landfill Gas-fired IC	1.8	8/2014	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

GPC is not within the FRCC region, and therefore not subject to its minimum reserve margin requirements. GPC operates within SERC, and as part of the Southern Power Pool has a planning reserve margin of 15 percent after 2015. Figure 35 displays the forecasted planning reserve margin for GPC through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, GPC has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 35: GPC - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by multiple municipal electric utilities located throughout Florida. It is collectively the state's eighth largest TYSP utility. As FMPA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (ARP). FMPA plans and supplies all of the power requirements for the ARP utilities

Load and Energy Forecast

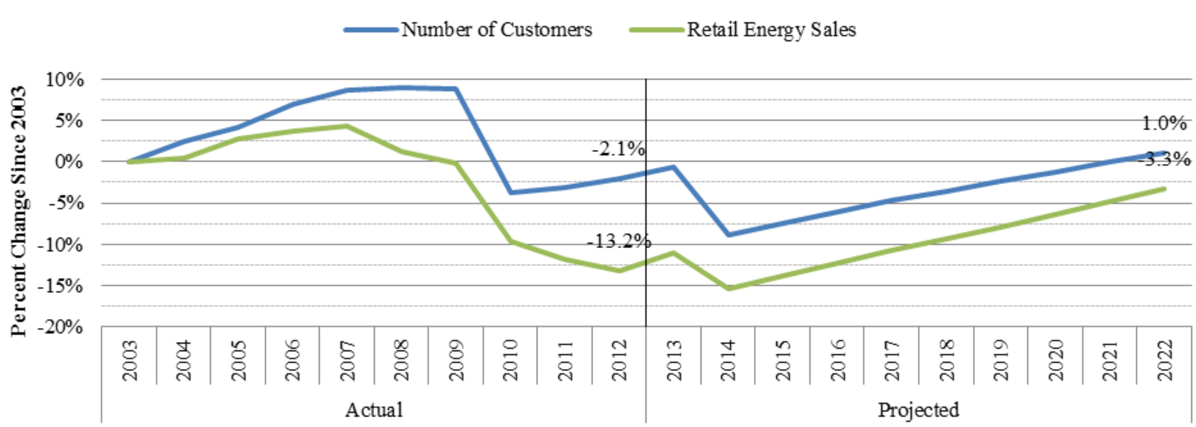
In 2012, FMPA's members had approximately 265,300 customers, with total retail energy sales of 5,549 GWh, or approximately 2.6 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 36.

Figure 36: FMPA - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 37 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, FMPA has seen a decrease in customers by 2.1 percent, and a decrease in retail energy sales by 13.2 percent. The company does not project to exceed its 2003 retail energy sales within the next ten years.

Figure 37: FMPA - Customer and Retail Energy Sale Growth Since 2003



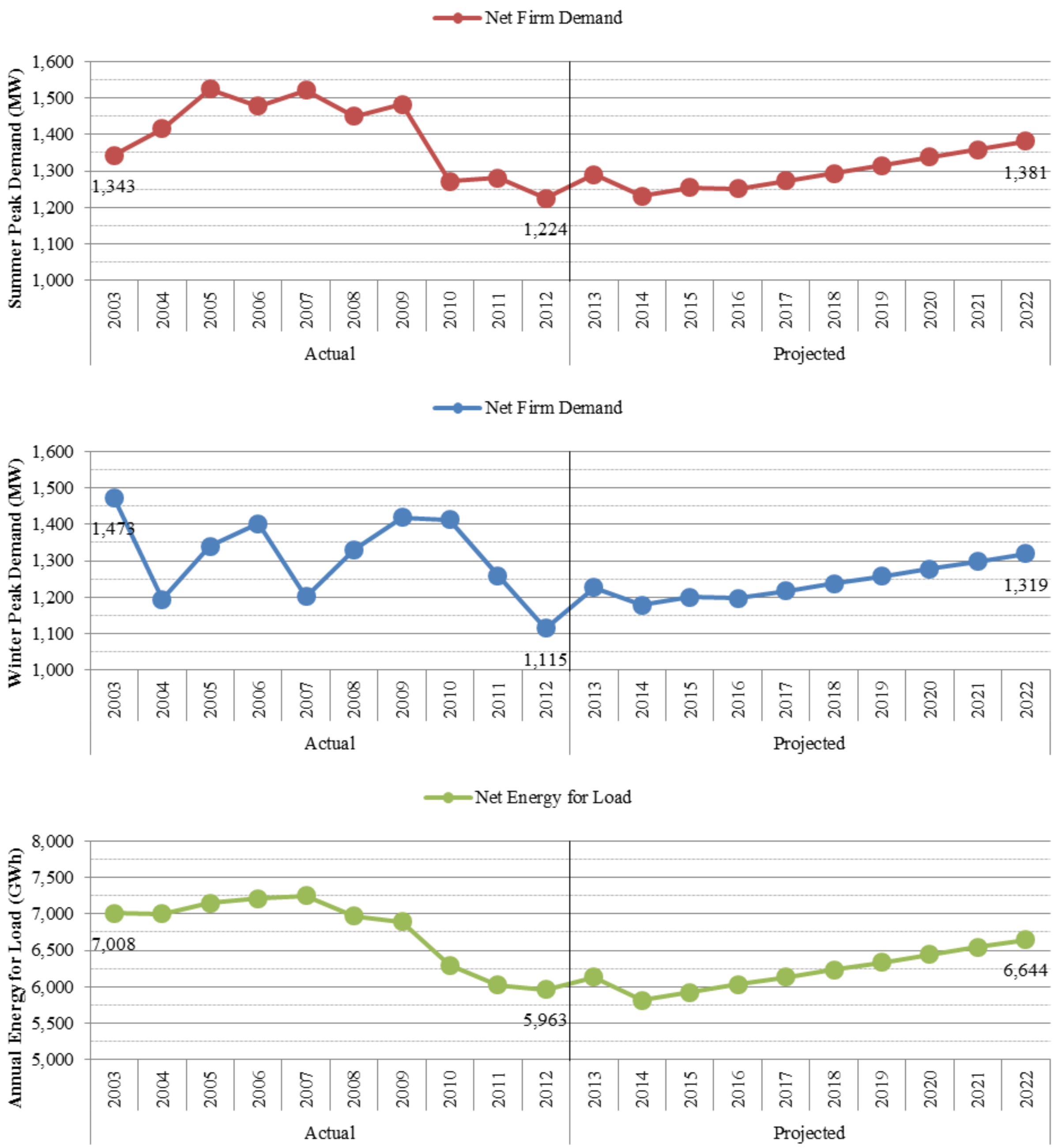
Source: 2013 TYSP Schedule 2

Florida Municipal Power Agency (FMPA)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 38 show FMPA's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of member utility's DSM programs. As FMPA did not provide separate annual conservation data, only the utility's net firm demand and net energy for load are shown below.

Figure 38: FMPA - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



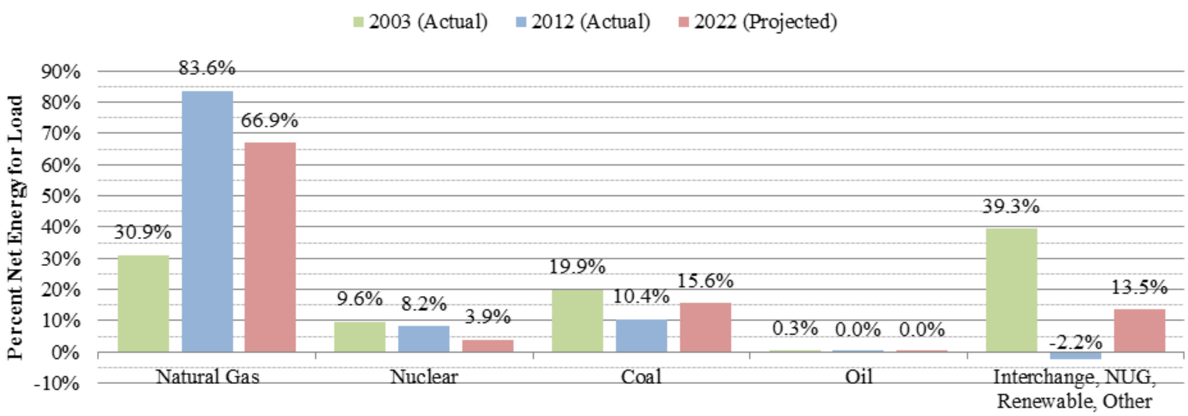
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 39 shows FMPA's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas is the primary generation fuel on FMPA's system, contributing 81.9 percent of system energy in 2012. A slight reduction in usage is forecast by 2022, with an increase in purchased power and coal usage reducing natural gas to approximately two-thirds of energy generation.

Figure 39: FMPA - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

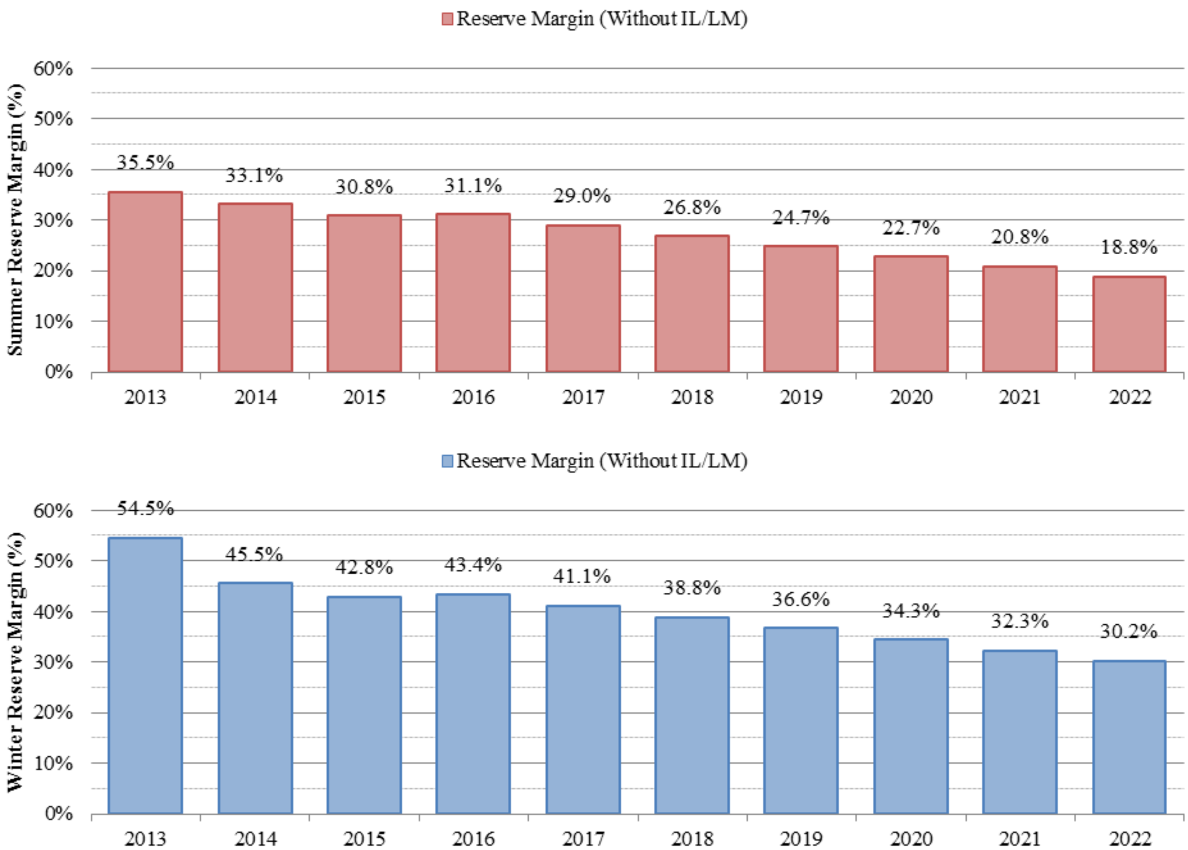
Planned Generation

FMPA's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

FMPA maintains a 15 percent reserve margin based on FRCC planning requirements. In addition, the utility uses a planning reserve margin of 18 percent for summer peak reserve margin planning. Figure 40 displays the forecasted planning reserve margin for FMPA through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, FMPA is a summer-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 40: FMPA - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the state's smallest TYSP utility. The company's service area is within the FRCC region, and includes the City of Gainesville and its surrounding urban area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As GRU is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

Load and Energy Forecast

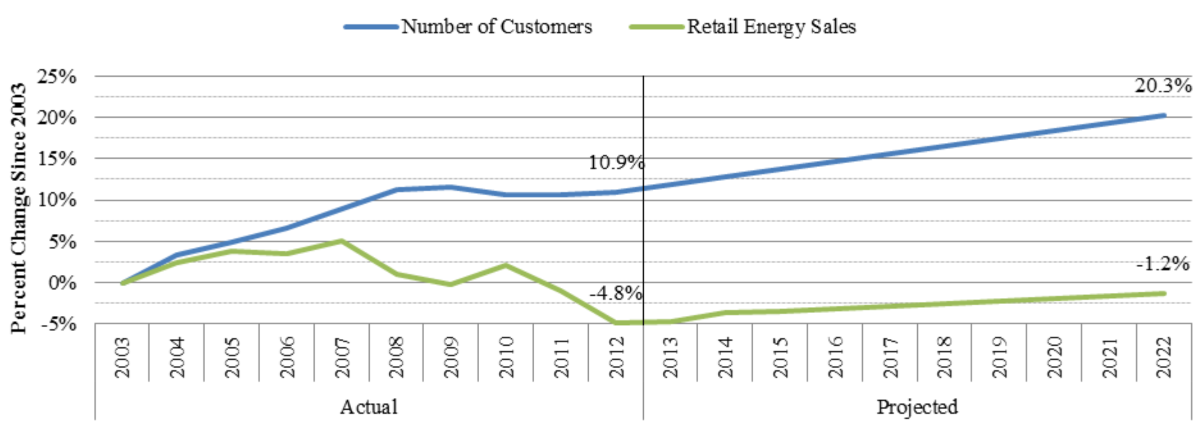
In 2012, GRU had approximately 95,600 customers, with annual retail energy sales of 1,675 GWh, or approximately 0.8 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 41.

Figure 41: GRU - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 42 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, GRU has increased its number of customers by 10.9 percent, but retail energy sales have declined 4.8 percent. The company forecasts positive growth for the entire planning period, but does not project retail energy sales to exceed its 2003 level within the next ten years.

Figure 42: GRU - Customer and Retail Energy Sale Growth Since 2003

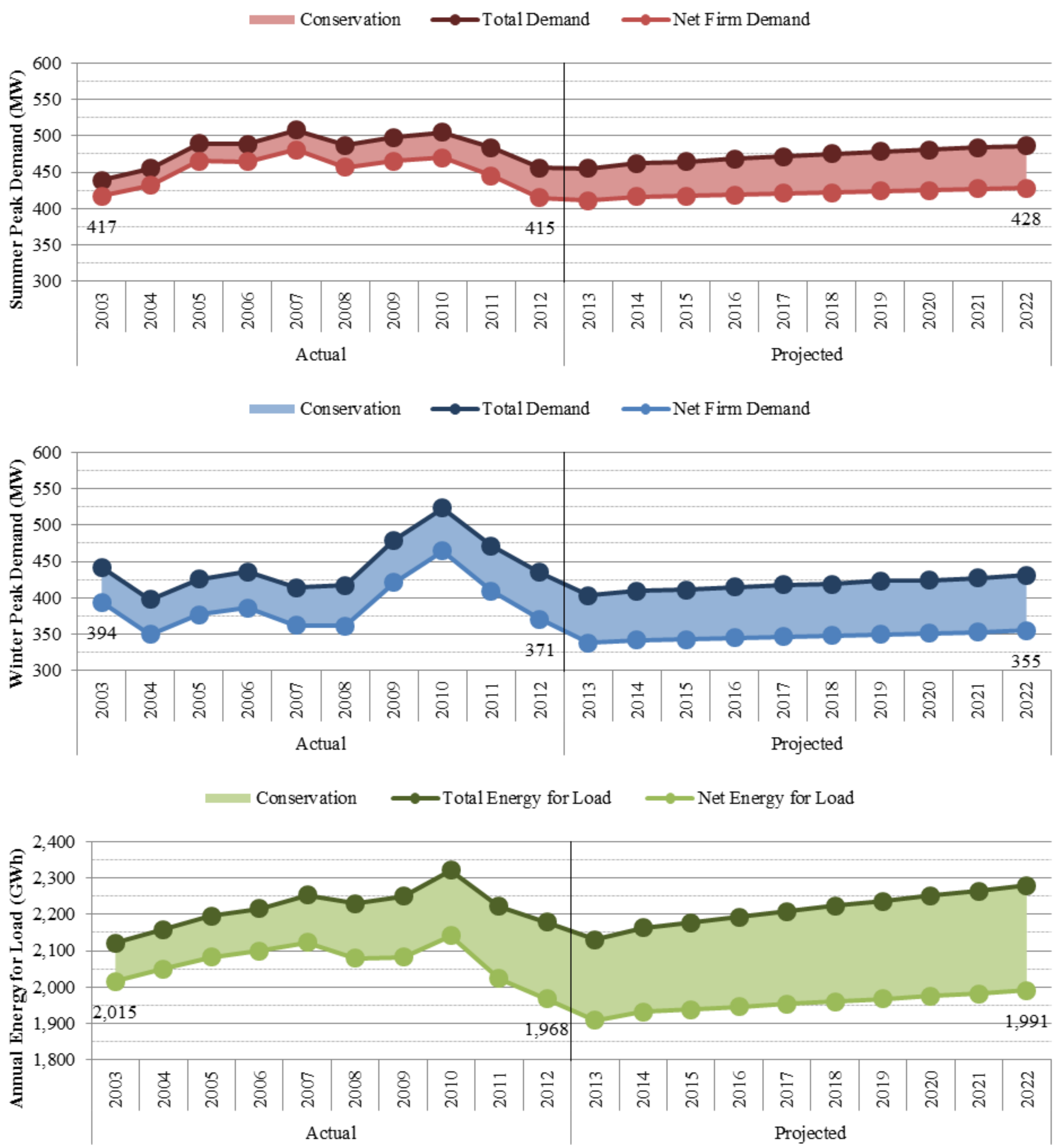


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 43 show GRU's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs.

Figure 43: GRU - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



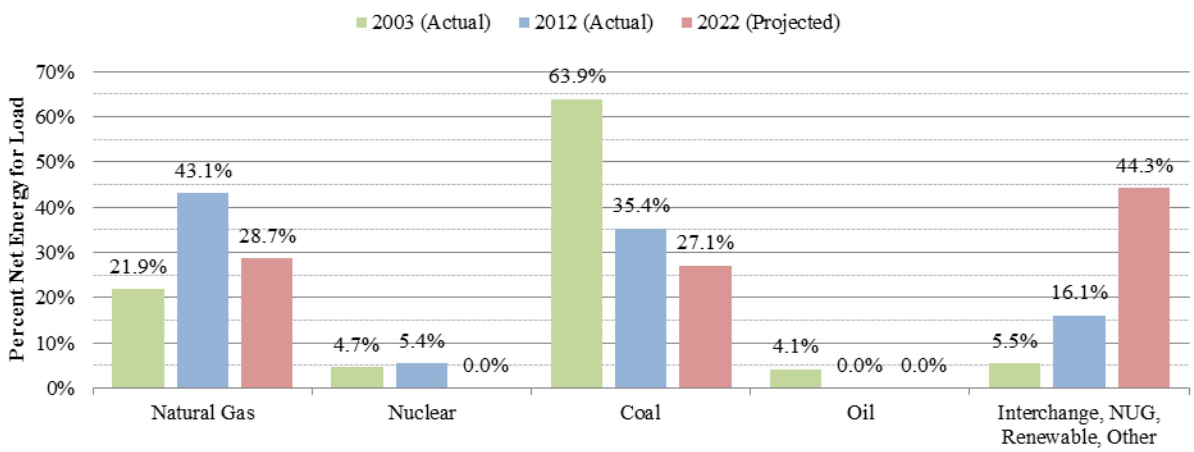
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 44 shows GRU's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. While the company has historically relied upon coal, natural gas was the dominant fuel in 2012, producing 43.1 percent of energy, over coal's contribution of 35.4 percent. All forms of native fuel use, including natural gas, nuclear, and coal, are anticipated to decline as purchased power is forecast to become the dominant fuel in 2022. A majority of this purchased power is associated with a single renewable PPA with the Gainesville Renewable Energy Center, a 100 MW biomass plant that utilizes wood and wood wastes for fuel.

Figure 44: GRU - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

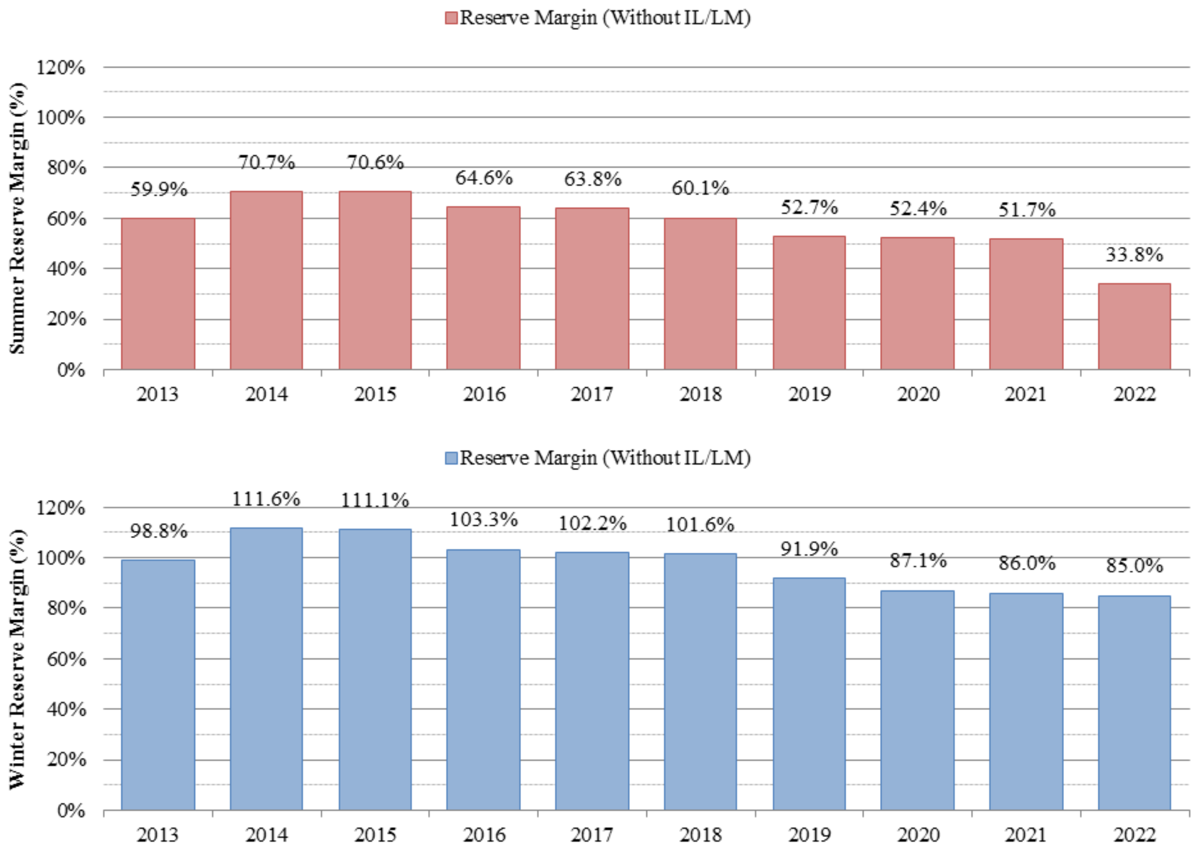
Planned Generation

GRU's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

GRU maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 45 displays the forecasted planning reserve margin for GRU through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, GRU is a summer-peaking utility. As the figure below illustrates, GRU's reserve margin is forecasted to remain well above the minimum level throughout the planning period.

Figure 45: GRU - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

JEA

JEA, formerly known as Jacksonville Electric Authority, is a municipal electric utility, and the state's fifth largest TYSP utility, and is the largest generating municipal 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 JEA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

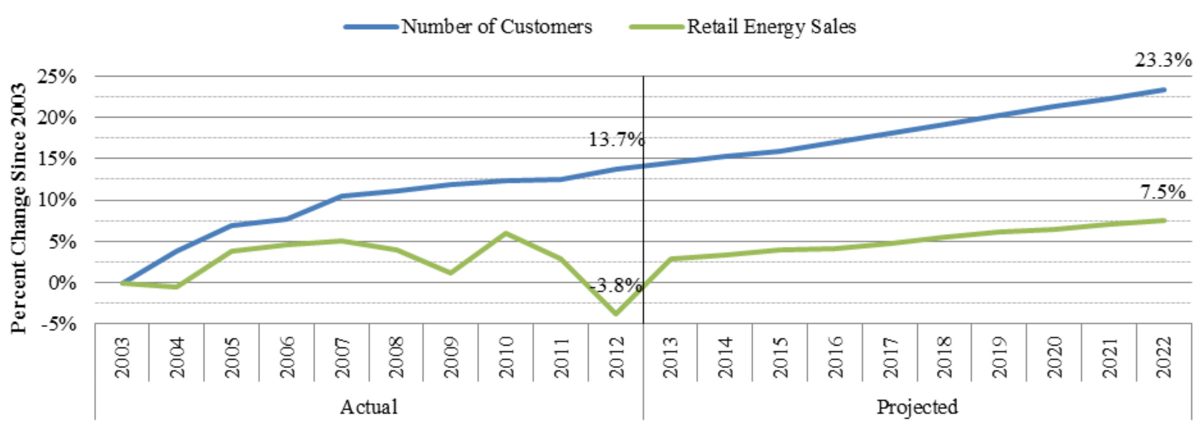
In 2012, JEA had approximately 420,600 customers, with annual retail energy sales of 11,540 GWh, or approximately 5.3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 46.

Figure 46: JEA - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 47 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, JEA has increased its number of customers by 13.7 percent, but retail energy sales have declined 3.8 percent. The company forecast growth for the entire planning period, with retail energy sales exceeding the historic 2010 peak by 2019.

Figure 47: JEA - Customer and Retail Energy Sale Growth Since 2003

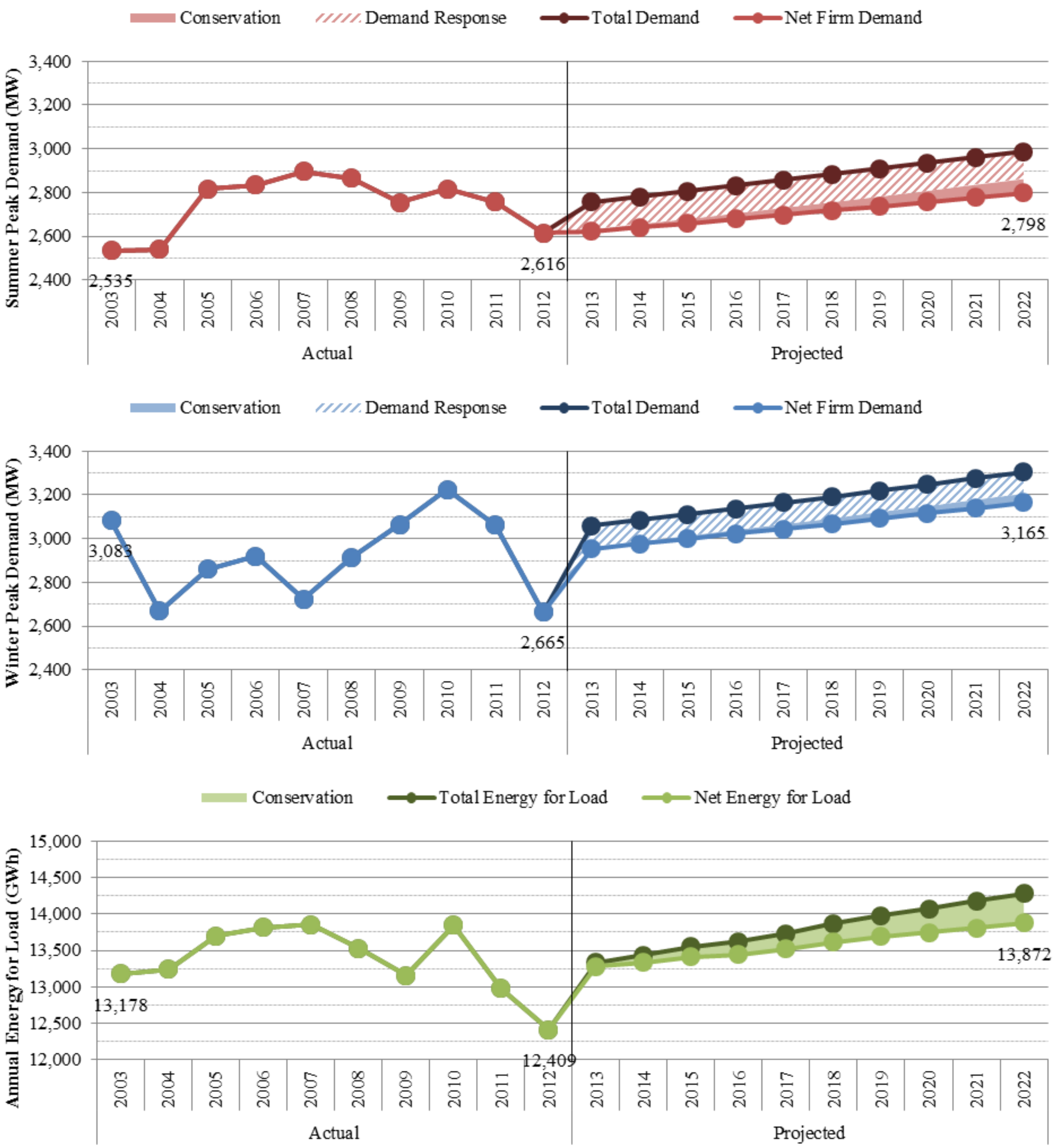


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 48 show JEA's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Historic conservation data is not available, so only net firm demand and net energy for load is shown for the previous ten years.

Figure 48: JEA - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



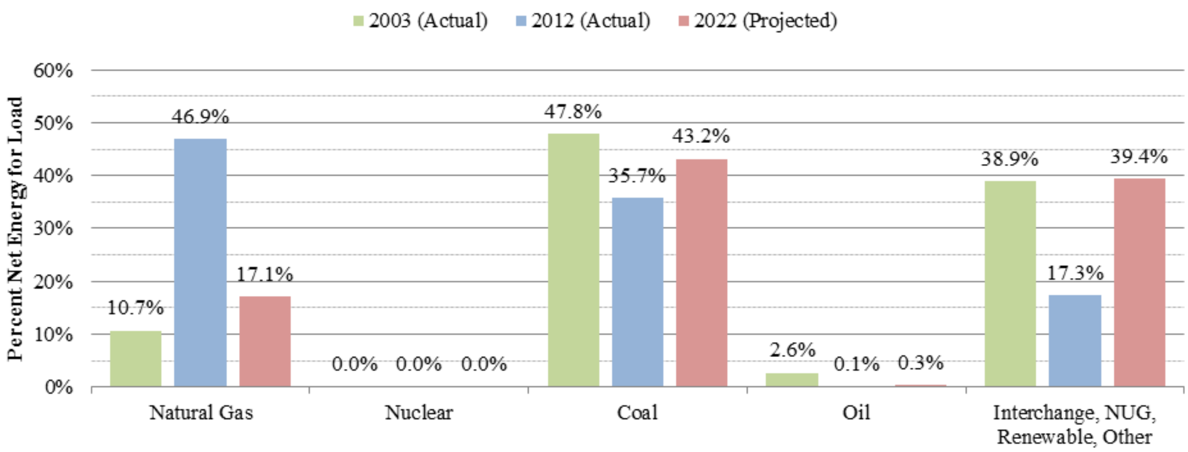
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 49 shows JEA's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas was the primary fuel on JEA's system in 2012, contributing 46.9 percent of energy. Coal is anticipated to become the dominant fuel by the end of the planning period, with 43.2 percent system energy in 2022, with the next largest fuel source being the combined category of interchange, non-utility generators, renewables, and other fuels. Petroleum coke, classified as 'other' below, makes up a majority of this category for JEA.

Figure 49: JEA - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

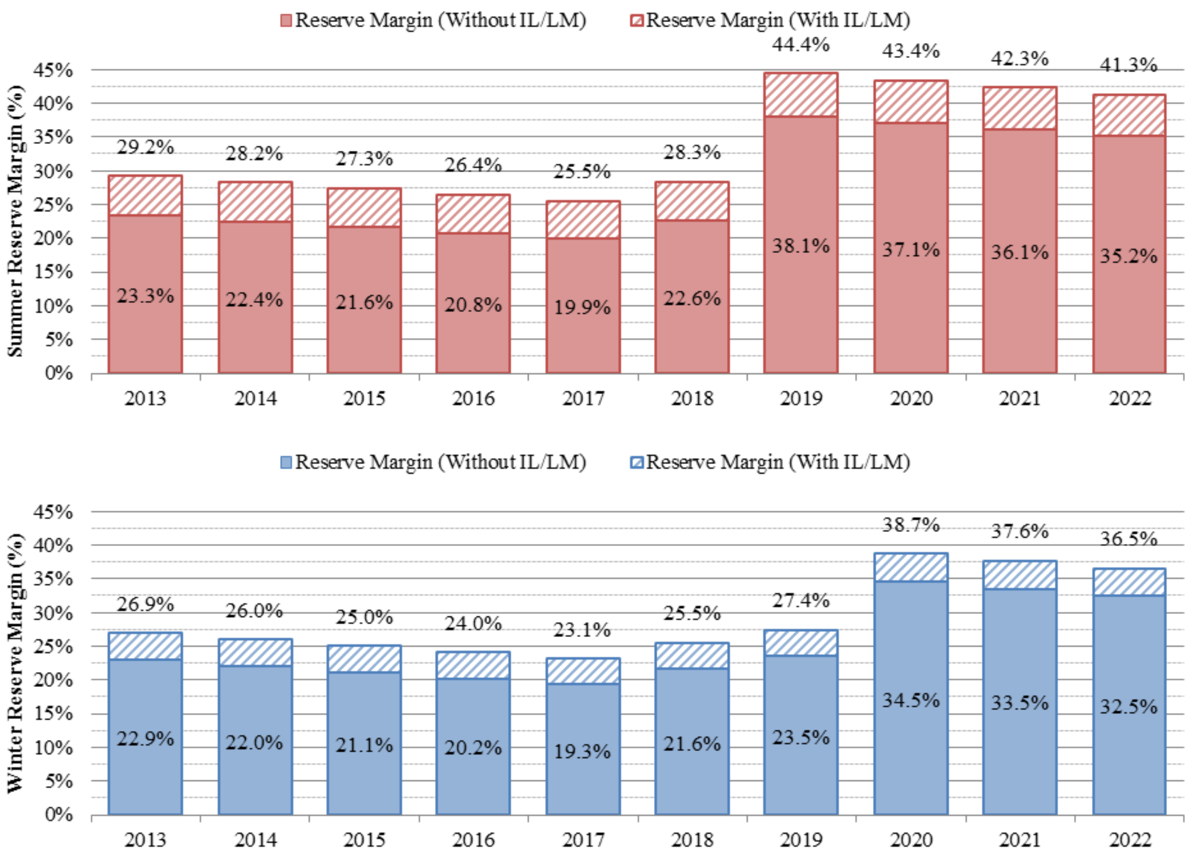
Planned Generation

JEA's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

JEA maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 50 displays the forecasted planning reserve margin for JEA through the planning period for both seasons, including the effects of projected conservation activities. The impact of demand response programs is also included in the figure below. As shown in the figure, JEA is a winter-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period. The increase in reserve margin in 2019 is associated with the expiration of a power sale with FPL from a jointly owned unit. FPL anticipates this sale will expire at an earlier period, in 2017.

Figure 50: JEA - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Lakeland Electric (LAK)

LAK is the municipal utility, and is the state's third smallest TYSP utility. LAK is owned and operated by the City of Lakeland. As LAK is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

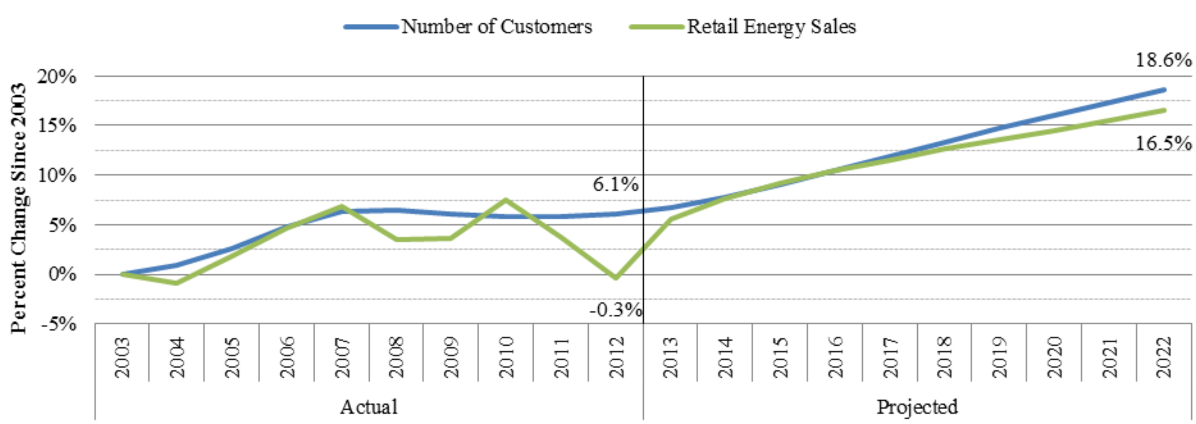
In 2012, LAK had approximately 113,100 customers, with annual retail energy sales of 2,612 GWh, or approximately 1.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 51.

Figure 51: LAK - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 52 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, LAK has increased its number of customers by 6.1 percent, while retail energy sales have declined 0.3 percent. The company forecasts positive growth for all years of the planning period, with retail energy sales exceeding the historic 2010 peak by 2014.

Figure 52: LAK - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 53 show LAK's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. As LAK did not provide separate annual conservation data, only the utility's net firm demand and net energy for load are shown below.

Figure 53: LAK - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)

Source: 2013 TYSP Schedule 3

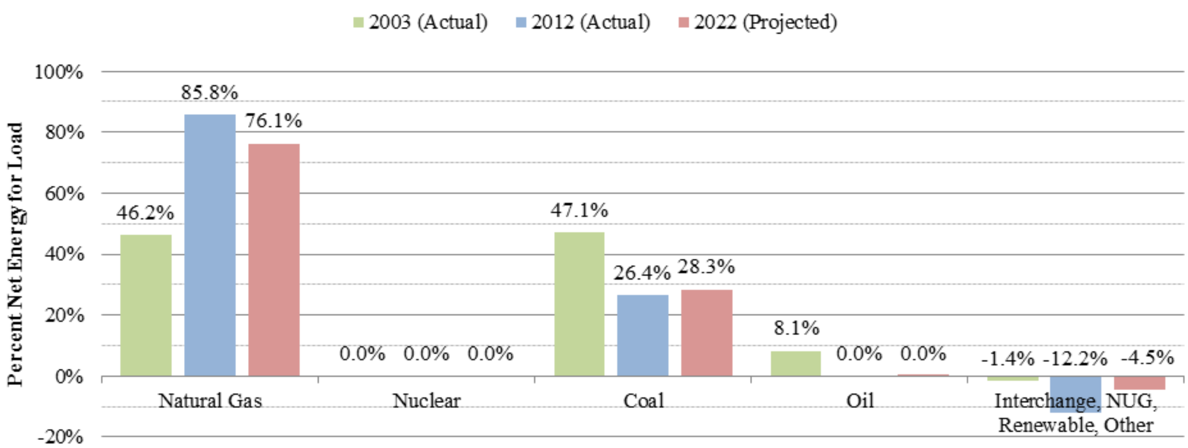
Lakeland Electric (LAK)

Generation Resources

Fuel Diversity

Figure 54 shows LAK's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas was the primary fuel on LAK's system, contributing 85.8 percent of system energy. With a total of 12.2 percent of system energy as exports, coal made up the remaining generation. Overall, natural gas is forecast to slightly decline along with exports, while coal remains at a little over a quarter of system energy.

Figure 54: LAK - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

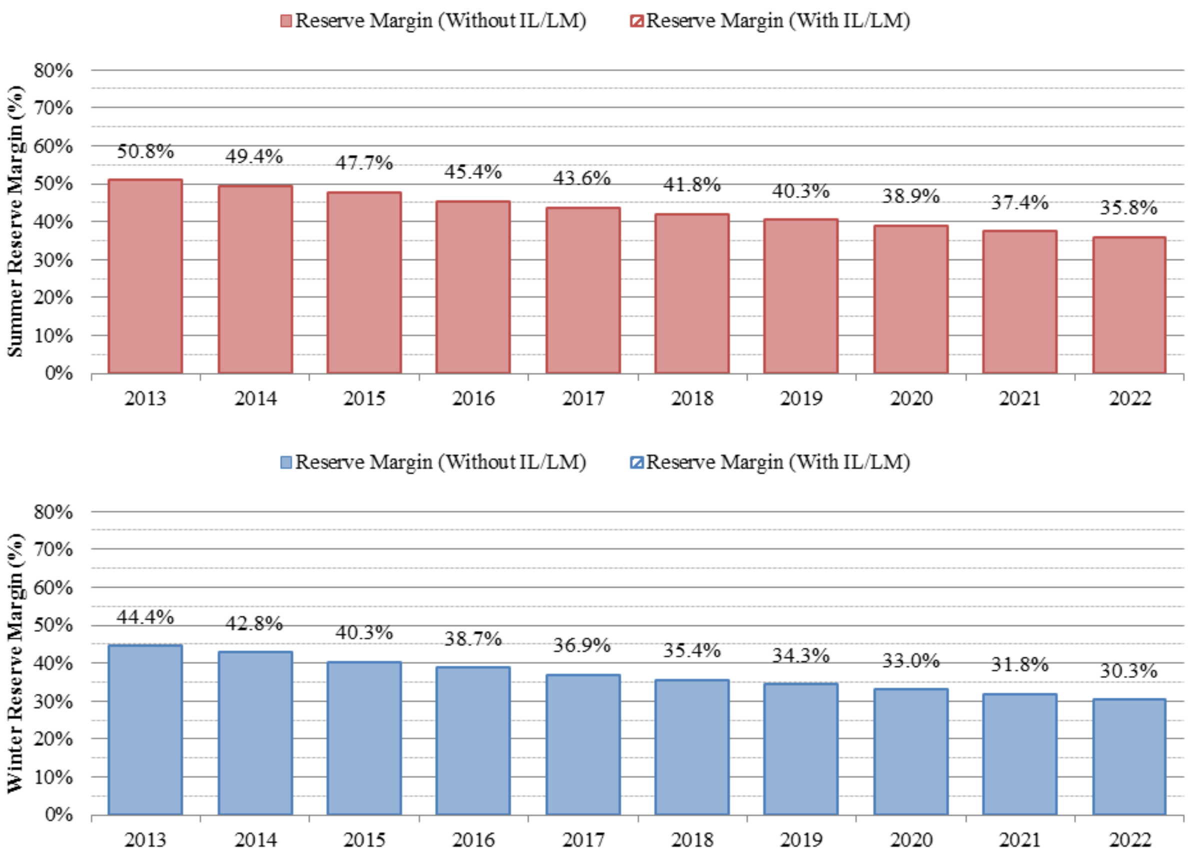
Planned Generation

LAK's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation additions through 2021.

Reserve Margin

LAK maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 55 displays the forecasted planning reserve margin for LAK through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, LAK is a winter-peaking utility for most years and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 55: LAK - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Orlando Utilities Commission (OUC)

OUC is a municipal utility, and the state's seventh largest TYSP utility. The utility's service territory is within the FRCC region, and serves the Orlando metropolitan area. As OUC is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

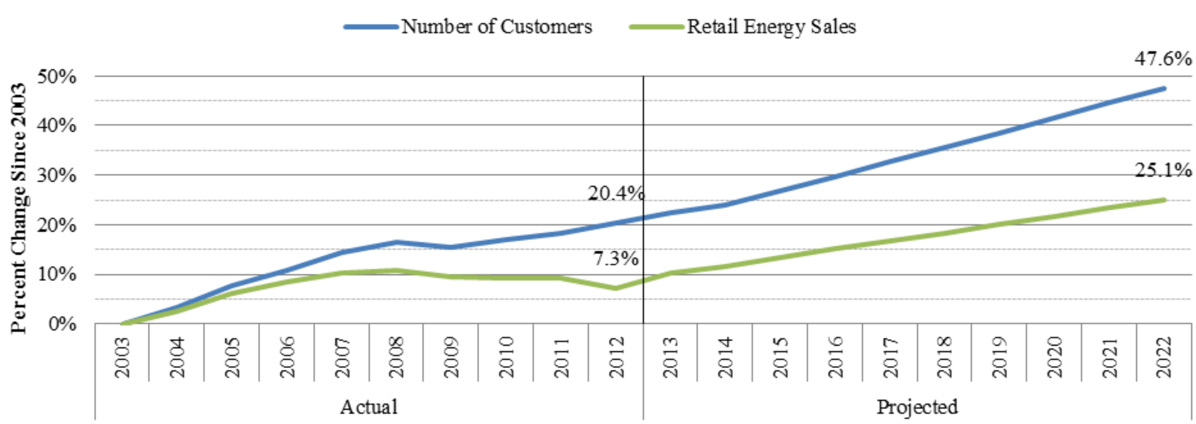
In 2012, OUC had approximately 213,300 customers, with annual retail energy sales of 5,851 GWh, or approximately 3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 56.

Figure 56: OUC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 57 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, OUC has increased its number of customers by 20.4 percent, and retail energy sales have increased by 7.3 percent. The company forecasts continued positive growth throughout the planning period, with retail energy sales exceeding the historic 2008 peak by 2014.

Figure 57: OUC - Customer and Retail Energy Sale Growth Since 2003

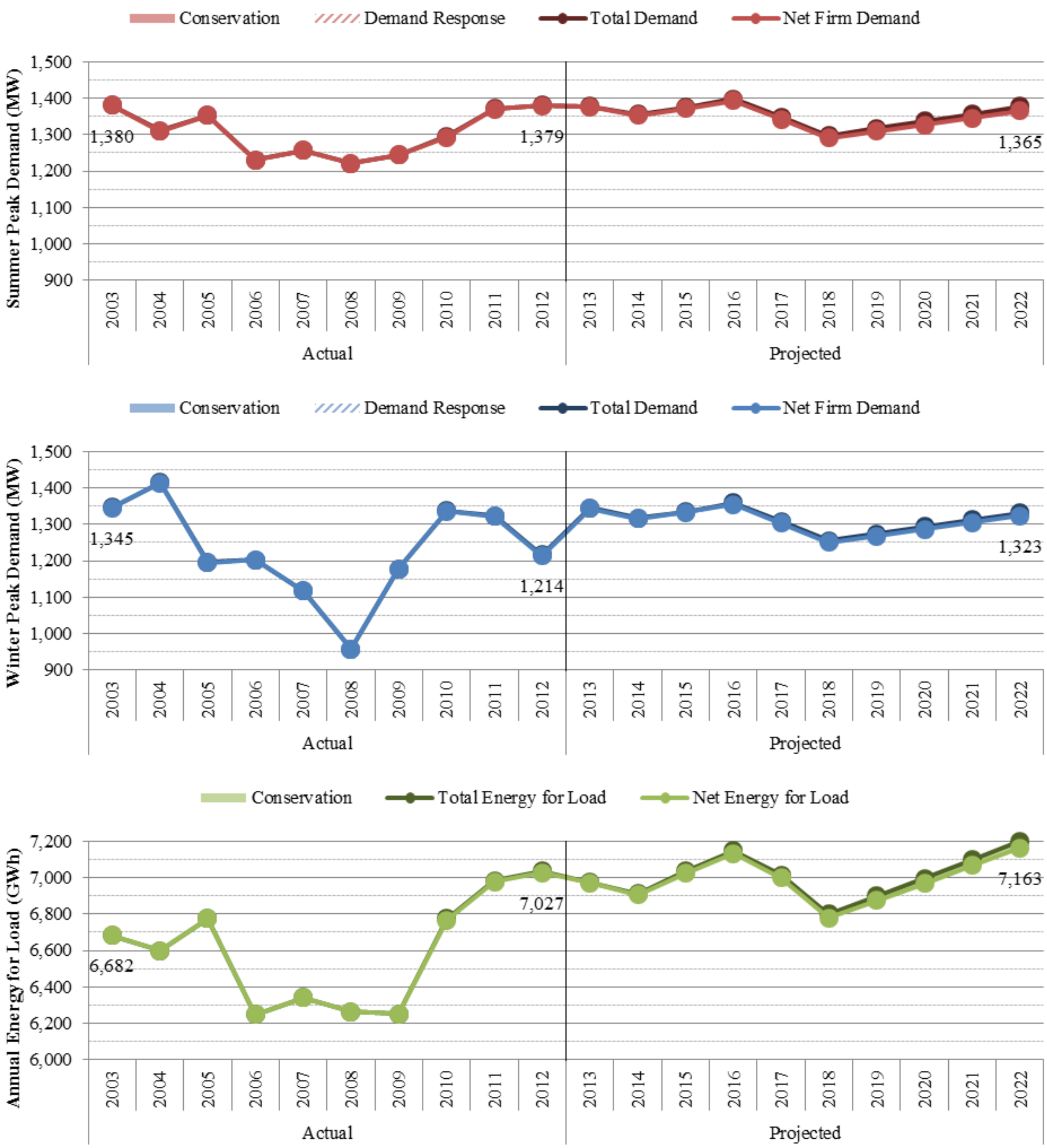


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 58 show OUC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon. Figure 58 below includes the effect of the utility's DSM programs.

Figure 58: OUC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



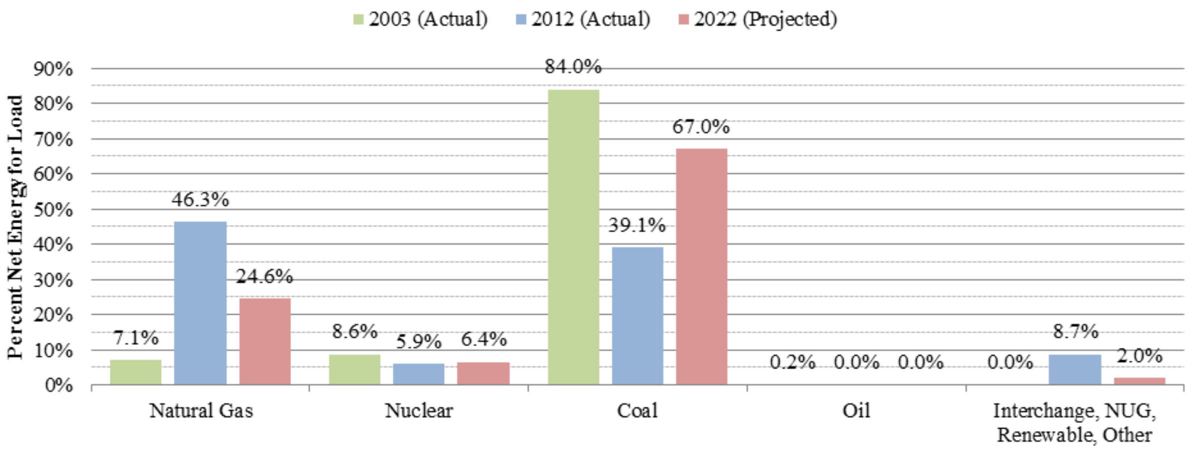
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 59 shows OUC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas is the primary fuel on OUC's system in 2012, contributing 46.3 percent of system energy. This is projected to decline to under a quarter of system energy by 2022, with coal producing approximately two-thirds of system energy by the end of the planning period.

Figure 59: OUC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

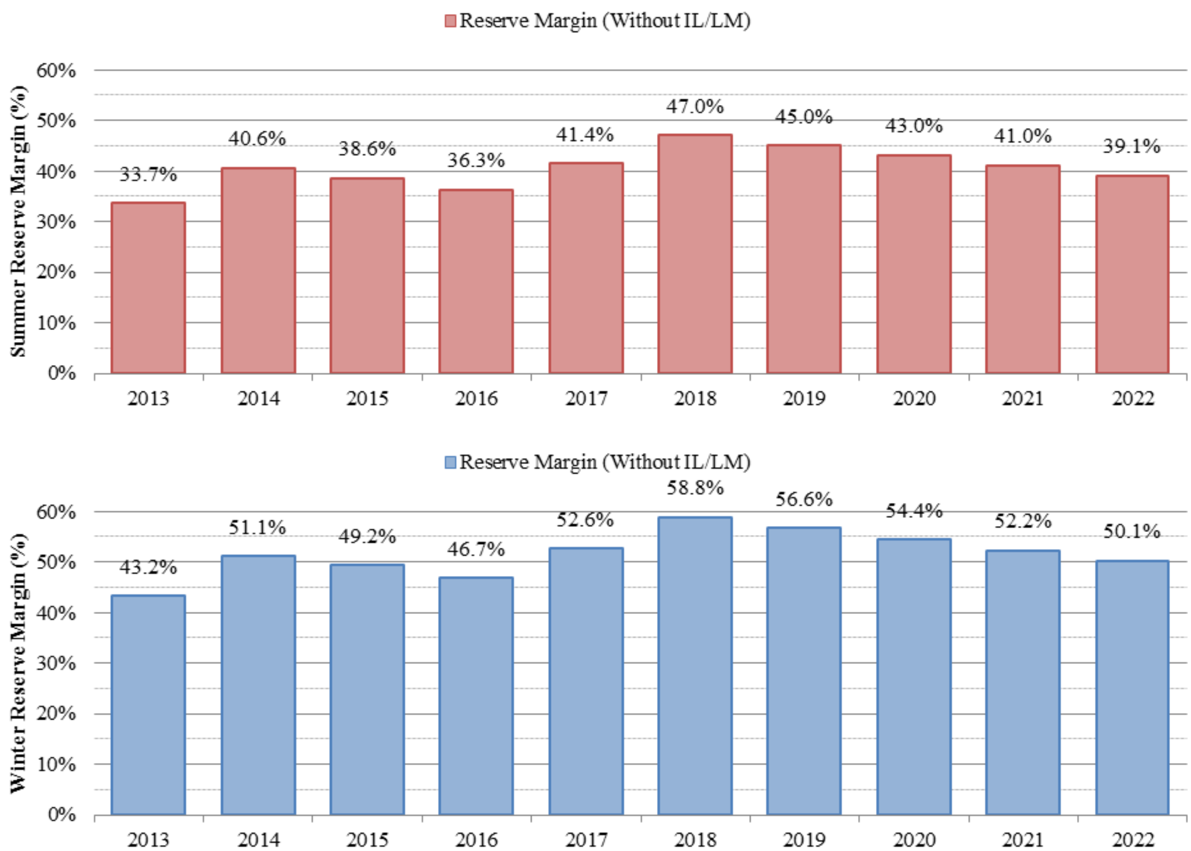
Planned Generation

OUC's 2013 TYSP did not contain any planned generation additions. This represents a decrease from the company's 2012 TYSP, which included a single combustion turbine.

Reserve Margin

OUC maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 60 displays the forecasted planning reserve margin for OUC through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, OUC is a summer-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 60: OUC - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves only wholesale customers that purchase power from SEC under long-term wholesale power contracts, and is collectively the state's fourth largest TYSP utility. SEC is within the FRCC Region, with load serviced throughout the State of Florida. Its generation assets are primarily within the central region. As SEC is a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

Load and Energy Forecast

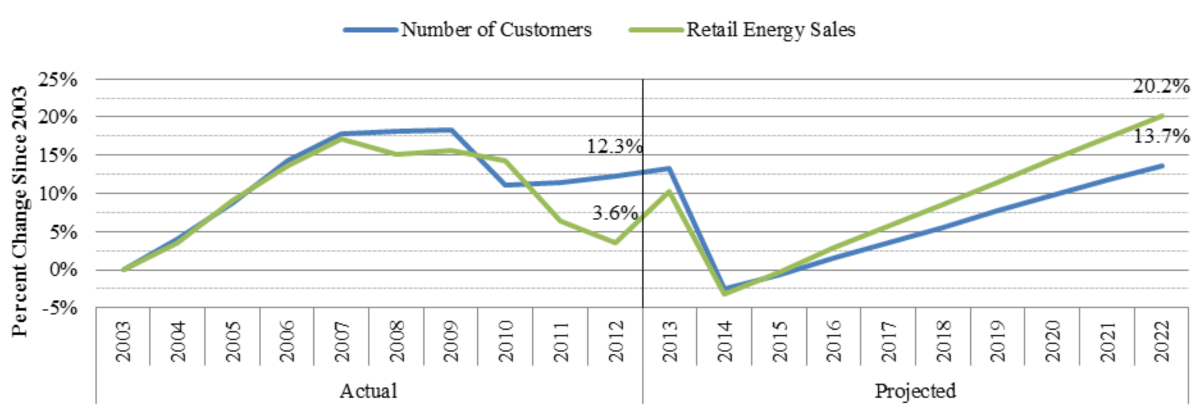
In 2012, SEC's members had approximately 850,000 customers, with annual retail energy sales of 14,387 GWh, or approximately 6.7 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 61.

Figure 61: SEC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 62 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, SEC's member cooperatives had increased the number of customers by 12.3 percent and retail sales by 3.6 percent. The company forecasts a decline in 2014 due to the loss of Lee County Electric Cooperative, which will purchase power from FPL. but otherwise positive annual growth over the planning period, with retail energy sales exceeding the historic 2007 peak by 2021.

Figure 62: SEC - Customer and Retail Energy Sale Growth Since 2003

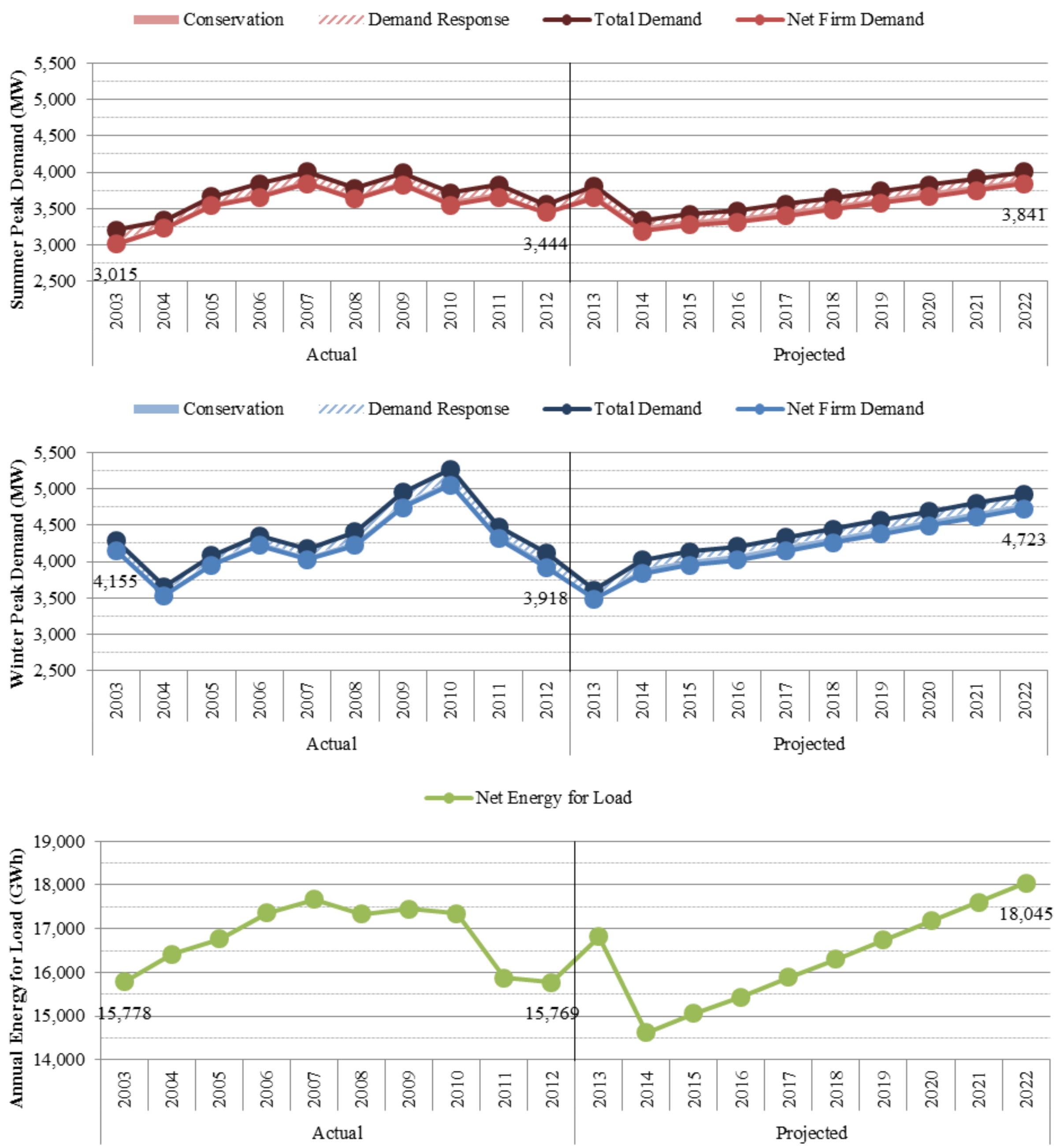


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 63 show SEC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon. Figure 63 below includes the effect of member cooperative's DSM programs.

Figure 63: SEC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



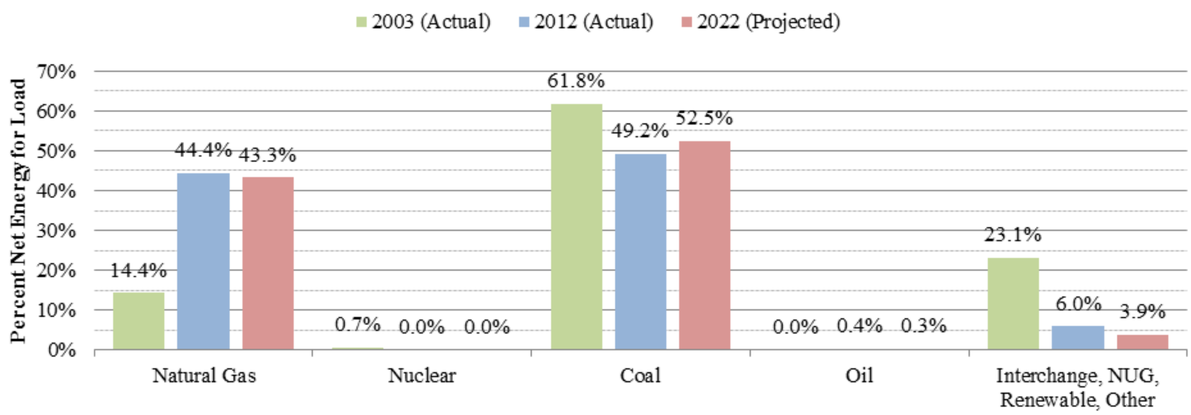
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 64 shows SEC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. SEC's primary generation fuel is coal, with 49.2 percent of system energy generated by coal. Coal usage has declined however, primarily with the increase of natural gas, which is the next highest fuel for SEC's system energy. Natural gas has risen to 44.4 percent of system energy in 2012, up from only 14.4 percent in 2003. Coal is anticipated to remain the main system fuel throughout the planning period, making up 52.5 percent in 2022, although natural gas is projected to increase its share of system energy to 43.3 percent in 2022.

Figure 64: SEC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

SEC's 2013 TYSP includes a total of nine planned generating units, two combined cycles and seven combustion turbines. With the exception of one of the combined cycle units, all are to be sited at a location to be determined in Gilchrist County. The planned units are detailed below in Table 22. This represents a decrease in the number and total capacity of generation additions from the company's 2012 TYSP, which included three combined cycle units and nine combustion turbines.

Table 22: SEC - Planned Generation Additions

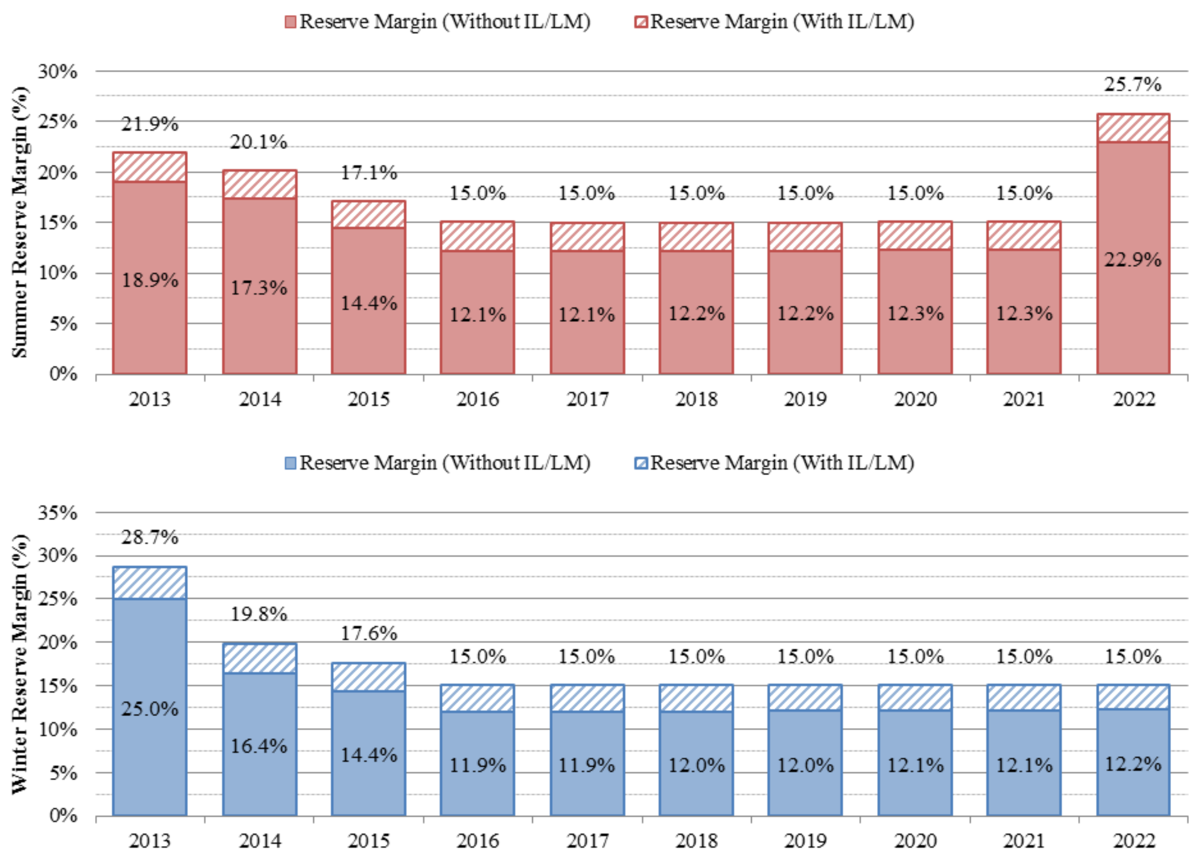
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Unnamed CT 1	Combustion Turbine	198	12/2019	N/A
Unnamed CC 1	Combined Cycle	192	12/2020	Required
Unnamed CC 2	Combined Cycle	192	12/2020	Required
Unnamed CT 2	Combustion Turbine	198	12/2020	N/A
Unnamed CT 3	Combustion Turbine	198	12/2020	N/A
Unnamed CT 4	Combustion Turbine	198	12/2021	N/A
Unnamed CT 5	Combustion Turbine	198	12/2021	N/A
Unnamed CT 6	Combustion Turbine	198	12/2021	N/A
Unnamed CT 7	Combustion Turbine	198	12/2021	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

SEC is within the FRCC region and is required to meet a 15 percent reserve margin requirement for planning purposes. Figure 65 displays the forecasted planning reserve margin for SEC through the planning period for both seasons, including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, SEC has sufficient reserve margin to meet projected customer demands for both seasons throughout the period when including demand response.

Figure 65: SEC - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7

City of Tallahassee Utilities (TAL)

TAL is a municipal utility, and the state's second smallest TYSP utility. The utility's service territory is within the FRCC region, in Leon County, and primarily serves the City of Tallahassee. As TAL is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

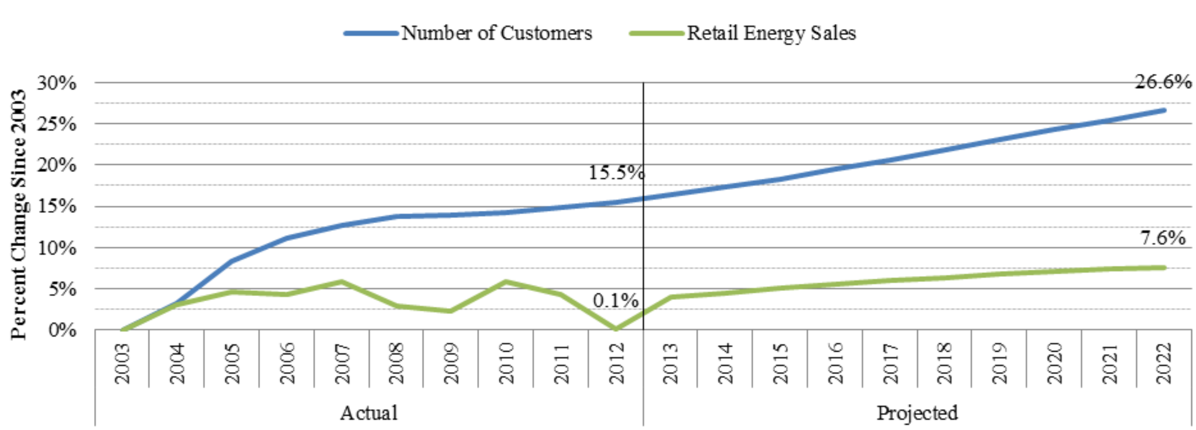
In 2012, TAL had approximately 115,000 customers, with annual retail energy sales of 2,604 GWh, or approximately 1.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 66.

Figure 66: TAL - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 67 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, TAL has increased its total number of customers by 15.5 percent, while only increasing retail energy sales by 0.1 percent. The company forecasts continued positive growth for the next ten years, with retail energy sales exceeding the historic 2007 peak by 2017.

Figure 67: TAL - Customer and Retail Energy Sale Growth Since 2003

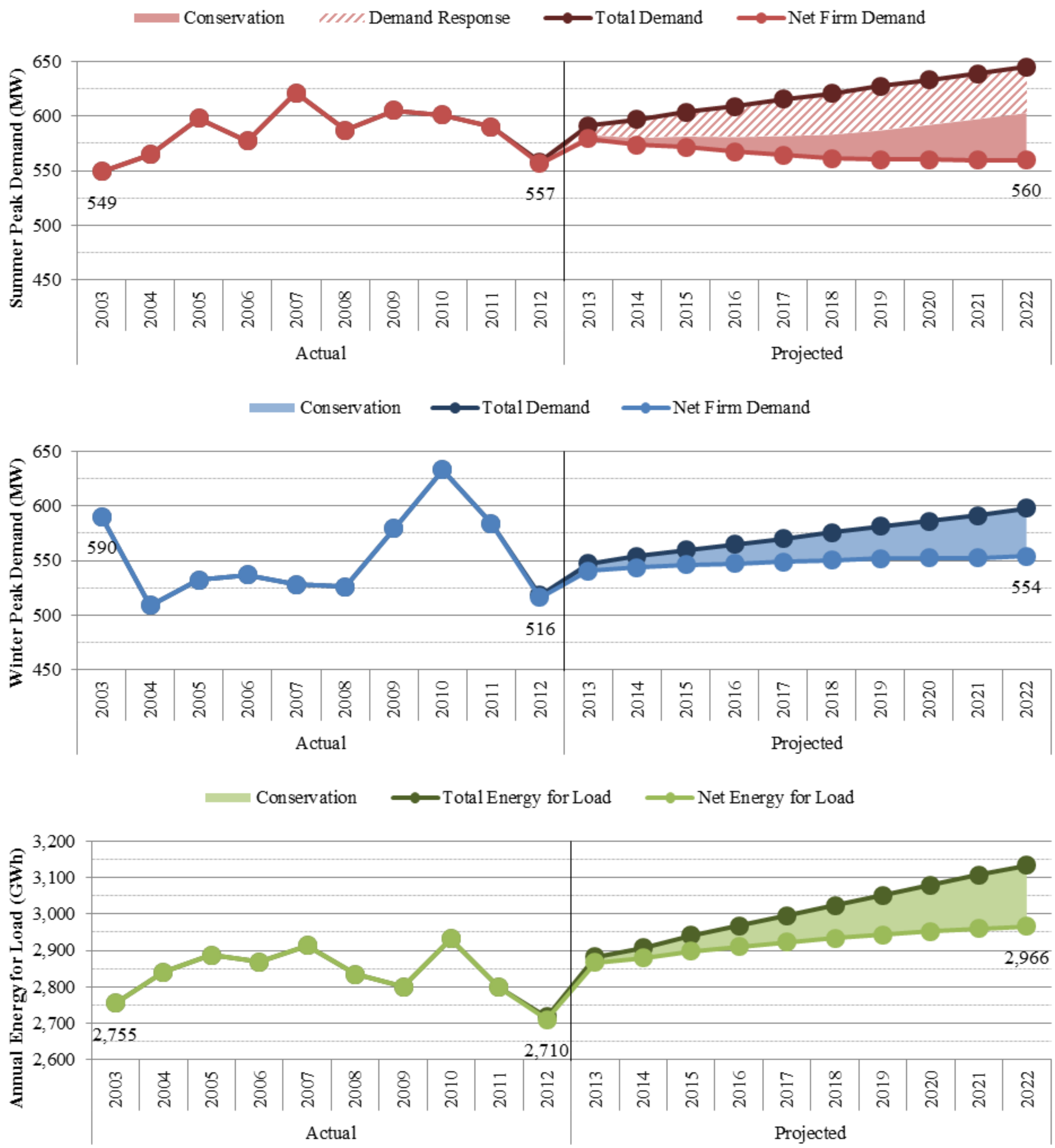


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 68 show TAL's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of DSM. As seen below, TAL has a demand response program for summer peak demand, but not for the winter period.

Figure 68: TAL - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



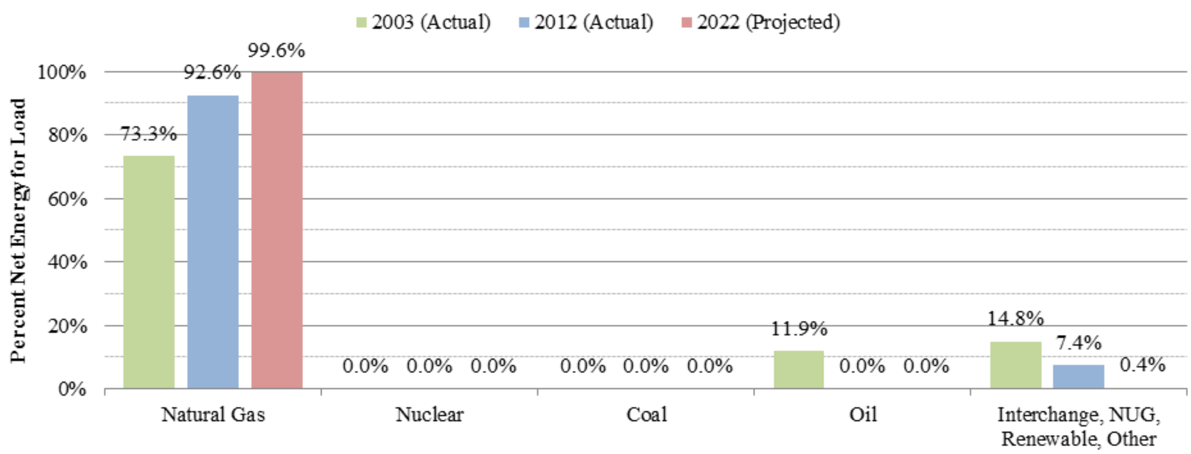
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 69 shows TAL's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. TAL relies almost exclusively on natural gas for its generation, excluding some small amount of purchases from other utilities. This dependency is anticipated to remain throughout the planning period, with only natural gas-fired generation to be added, and purchases from other utilities forecasted to decrease.

Figure 69: TAL - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

TAL's 2013 TYSP includes a single generating unit addition at their existing Hopkins plant site in Leon County. The unit is detailed below in Table 23. This represents an increase over the company's 2012 TYSP, which included no generation additions.

Table 23: TAL - Planned Generation Additions

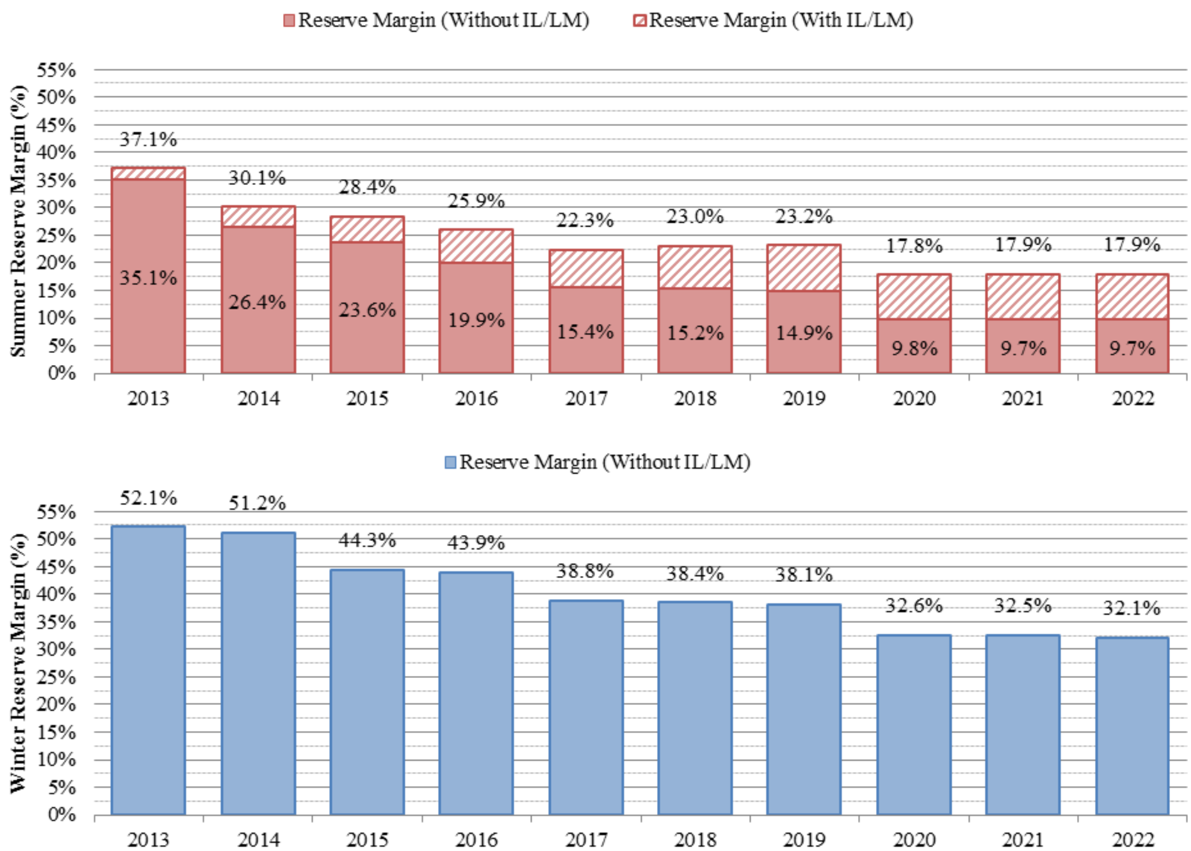
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Hopkins 5	Combustion Turbine	46	5/2020	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

TAL is within the FRCC region and is required to meet a 15 percent reserve margin requirement. However, TAL has adopted a 17 percent planning reserve margin requirement. Figure 70 displays the forecast planning reserve margin for TAL through the planning period for both seasons including the effects of projected conservation activities. The impact of the utility's demand response programs, which are focused on summer demand only, is also included in the summer reserve margin. As shown in the figure, TAL is a summer peaking utility and has sufficient reserve margin to meet projected customer demands throughout the period when including demand response.

Figure 70: TAL - Seasonal Reserve Margin (Summer & Winter)



Source: Based on 2013 TYSP Schedules 3 & 7