# REVIEW OF THE 2011 TEN-YEAR SITE PLANS

## FOR FLORIDA'S ELECTRIC UTILITIES

*Florida Public Service Commission*

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## STATEWIDE PERSPECTIVE



## INDIVIDUAL UTILITIES

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# UTILITIES FILING A TEN-YEAR SITE PLAN

## Investor-Owned Utilities

| | |
|---|---|
| FPL | Florida Power & Light Company |
| Gulf | Gulf Power Company |
| PEF | Progress Energy Florida, Inc. |
| TECO | Tampa Electric Company |

## Municipal Utilities

| | |
|---|---|
| FMPA | Florida Municipal Power Agency |
| GRU | Gainesville Regional Utilities |
| JEA | JEA |
| LAK | City of Lakeland |
| OUC | Orlando Utilities Commission |
| TAL | City of Tallahassee |

## Rural Electric Cooperatives

| | |
|---|---|
| SEC | Seminole Electric Cooperative |

# 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 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 for the 2011 Ten-Year Site Plans for Florida's electric utilities. All findings of the Commission are made available to the Florida 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)[1]. 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 web site and is available to the public.

The Commission has reviewed the Ten-Year Site Plans 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. Therefore, the Commission finds the 2011 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes.

Since the Ten-Year Site Plan 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.

The 2011 TYSPs differ from those produced in previous years in two significant ways: the projected annual growth rate of customers has once again turned positive, and the estimate of energy consumption per residential customer has risen dramatically, well above the level that was forecasted in the previous two years. Both of these factors indicate that the electric industry in Florida is beginning a return to patterns of growth which are more consistent with historic levels. The four largest investor-owned utilities (IOUs) – Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), and Gulf Power Company (Gulf) – are reporting positive growth in all customer classes (except Gulf's commercial/industrial class) for the first time since 2006, but the rate of growth is well below historical norms for all four utilities.

The 2011 TYSPs identify an increase of generating capacity in the State of Florida by approximately 9,000 megawatts (MW) over the planning horizon. This figure represents an increase of about 4,000 MW from last year's Ten-Year Site Plans. The 2011 Plans include retirements and uprates of existing units along with new generating units to be added during the ten-year horizon, all of which are natural gas-fired units. As in previous planning cycles, the

[1] The Power Plant Siting Act is Sections 403.501 through 403.518, Florida Statutes

addition of these gas units will increase the percentage of natural gas used in Florida to generate electricity.

All TYSPs are subject to modification due to factors such as changes to fuel cost, energy use, evolving technology, and shifting energy policy. In fact, the information presented in the 2011 TYSPs for FPL and PEF has been modified significantly, rendering their 2011 TYSPs as filed obsolete. However, consideration of the supplemental data obtained through data requests brings these Plans up to date.

Three major changes in FPL's planning assumptions have occurred, all of which affect its system reliability and future need for additional generation in various ways. FPL's 2011 TYSP reports that it would need to begin scheduling planned maintenance of its generating units during peak demand periods, thereby reducing the capacity available at those critical times. However, FPL later informed the Commission that it had determined the required maintenance may be performed during the non-peak periods. FPL has indicated that this change results in 350 MW of additional capacity during its summer peak period, and 550 MW of additional capacity during its winter peak period. In addition, on July 26, 2011, the Commission found that the Demand-Side Management (DSM) Plan based on the 2009 goals filed by FPL would have an undue impact on the costs passed on to customers, and that the public interest would be served by modifying the DSM Plan such that it consists of those programs that were already in effect. Finally, on July 18, 2011, FPL filed a petition indicating its intention to modernize its Port Everglades plant by replacing four 1960s-era steam units with a new, highly efficient combined cycle (CC) power plant. This modernization will be done in order to meet a reliability need in 2016, which appears in FPL's 2011 Plan as a "greenfield" unit. The modernization project will produce a net increase in system capacity of only about 80 MW, but the new combined cycle unit will be approximately 35 percent more efficient than the older units.

PEF has also experienced changes to the planning assumptions used to produce its 2011 Ten-Year Site Plan. The TYSP submitted to the Commission in April 2011 includes capacity from PEF's Crystal River Unit 3 (CR3) nuclear facility, which at that time was out of service due to a delamination of the concrete containment structure discovered during a steam generator replacement project which began in October 2009. When the 2011 Plan was produced, PEF expected that the CR3 containment building would be repaired and the unit would be operational before the summer peak period in 2011. However, since that time another delamination has occurred, and PEF is now estimating the return to service of CR3 to be some time in 2014. Additionally, as with FPL, the Commission ruled on July 26, 2011, that PEF's DSM Plan based on the 2009 goal would have an undue impact on the costs passed on to customers, and that the public interest would be served by modifying the DSM Plan such that it consists of those programs that were already in effect.

PEF's 2011 TYSP identified a 178 MW combustion turbine (CT) in 2020 as its next planned generation addition. For PEF, the reduced savings from DSM would presumably act to accelerate the need for additional capacity in the short term. The effect of delaying CR3's return to service until 2014 would not cause the need for new generation to occur sooner than PEF's original 2011 TYSP. The reduced DSM savings, however, have accelerated the need for the new combustion turbine. Updated schedules obtained through data requests show the new

CT coming into service in 2018. In addition, the updated schedules include a new combined cycle unit with a summer capacity of 767 MW coming into service in 2020.

For these reasons, the Commission is continuing to closely monitor the developments in the planning processes of the reporting utilities, in order to ensure the reliability of the electric generation system in Florida, and the need for additional generation and transmission facilities in the state.

**Conservation and 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 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.

In 2009, the Commission established aggressive new conservation goals for the Florida Energy Efficiency and Conservation Act (FEECA)[2] utilities to meet through their DSM and energy efficiency programs. All six of the generating FEECA utilities have now incorporated these new goals into their 2011 TYSPs. However, in July 2011, the Commission found that the DSM Plans based on the 2009 goals filed by FPL and PEF would have an undue impact on the costs passed on to customers, and that the public interest would be served by modifying them such that the DSM Plans of both utilities consist of those programs that were already in effect. These modifications are likely to result in lower levels of demand and energy savings than that reflected in the 2011 TYSPs for FPL and PEF.

**Modernization of Existing Facilities**

Before an electric utility proceeds with plans to construct a new generating unit, it must consider all available options to meet additional need in the most reliable and cost-effective manner possible. The modernization of an existing unit can sometimes prove to be the best choice. The term "modernization" refers to the upgrading of older, less efficient units with new, cleaner burning and more fuel efficient technologies. Such projects usually require the removal of the older units, which will temporarily impact reliability until the new unit comes in-service. Consequently, a utility planning a modernization project must ensure that its reserves are sufficient for the duration of the outage prior to commencing with the construction.

The Commission approved two modernization projects for FPL in 2008, both of which are currently on schedule. The modernized unit at Cape Canaveral will be operational in 2013, and the new Riviera Beach combined cycle unit is scheduled to be online in 2014. Most recently, FPL has notified the Commission that it intends to modernize its Port Everglades unit. Before considering new generation, utilities are encouraged to address the feasibility of modernization by continuing to explore potential projects and to report such findings in next year's Ten-Year Site Plans.

[2] Sections 366.80-366.85 and 403.519, F.S.

## New Generation Facilities

The State of Florida currently has a total summer generating capacity of 57,605 MW installed. Of the approximately 9,000 MW of net capacity included in the 2011 Plans, about 5,300 MW are from new generation units to be installed, all of which will be natural gas-fired units. The remaining 3,700 MW are made up of new units already under construction and uprates of existing units.

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 the new generation facilities included in the 2011 Ten-Year Site Plans that are appearing for the first time, and which will require certification under the Power Plant Siting Act. Table 1 also includes PEF's additional CC unit which did not appear in the Plan, but rather was added in a data request.

**Table 1. Generation Units Requiring Certification**

| Year Planned | Utility | Location | Summer Net Capacity (MW) | Unit Type |
|---|---|---|---|---|
| 2016 | FPL | Port Everglades | 1,277 | Combined Cycle |
| 2020 | FPL | Unknown | 1,191 | Combined Cycle |
| 2020 | PEF | Unknown | 767 | Combined Cycle |
| 2020 | SEC | Unknown | 196 | Combined Cycle |
| 2020 | SEC | Unknown | 196 | Combined Cycle |

Source: Responses to Staff Data Requests.

## Fuel Diversity

Because a balanced fuel supply can enhance system reliability and significantly 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, the continuing trend of an increasing reliance on natural gas-fired generation is likely to persist into the foreseeable future. In previous Ten-Year Site Plans, Florida's utilities responded to fuel diversity concerns through the inclusion of multiple coal-fired power plants. Due to a combination of fuel cost uncertainties, high capital costs, and uncertainties regarding potential environmental costs related to possible carbon emission regulations, more than 4,000 MW of coal-fired generation has been canceled. In 2007 and 2008, the Commission approved the need for approximately 5,000 MW of new nuclear generation. However, over the course of the past two planning cycles, all of the new nuclear units have been delayed beyond the current ten-year planning horizon.

Currently, more than 50 percent of the electric power in Florida is generated by natural gas. The fact that the price of natural gas is expected to remain relatively low throughout the planning horizon is a major contributor to the forecast that natural gas will generate more than 55 percent of the electric energy in Florida by the year 2020.

Approximately 1,300 MW of renewable generation is currently operating in Florida, an increase of about 80 MW over the 2010 total. Presently almost 31 percent of all renewable generation in Florida comes from municipal solid waste (MSW). Other major types of renewable generation operating in the state include woody biomass (30 percent) and waste heat (22 percent). The remaining 17 percent is made up by a combination of landfill gas, hydroelectric generation, and both solar thermal and solar photovoltaic generation.

Historically, relatively high capital and operating costs, as well as limited physical applications, have hampered the development of renewable energy in Florida. Over the current ten-year planning horizon, approximately 765 MW of additional renewable generation is planned in the state, an increase of more than 30 MW from last year. The majority of these additions proposes to use biomass, with significant amounts from solar and MSW as well. 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 our state's reliance on expensive fossil fuels.

# INTRODUCTION

The Ten-Year Site 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. These comments are included in Appendix A of this review. Because the Ten-Year Site Plans 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, 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 all major generating electric utilities in Florida to submit a Ten-Year Site Plan to the Florida Public Service Commission for review not less often than biennially. In order to fulfill this statutory requirement, the Commission has adopted Rules 25-22.070 through 22.072, F.A.C. The Ten-Year Site Plans must contain projections of each utility's electric power needs, fuel requirements, and information regarding planned additional generating units (size, general location, etc.), as well as any major changes or additions to transmission facilities. Any generating utility in the state planning to build a new unit larger than 75 MW within the planning horizon is required to file a Ten-Year Site Plan. Otherwise, utilities with existing generating capacities below 250 MW are exempt from this requirement.

In accordance with Section 186.801, F.S., the Commission performs a preliminary study of each utility's Ten-Year Site Plan to determine whether each is suitable or unsuitable. This document, *Review of the 2011 Ten-Year Site Plans*, contains the results of the study. The Commission forwards this document to the Florida Department of Environmental Protection (DEP) for use in power plant siting proceedings.

In addition, Section 377.703(2)(e), F.S., requires the Commission to coordinate with the Department of Agriculture and Consumer Services (DACS) in its preparation of long-range forecasts of energy supply and demand. The *Review of the 2011 Ten-Year Site Plans*, which contains electricity and natural gas forecasts, is forwarded to the DACS.

### Information Sources

Contained in each utility's Ten-Year Site Plan is a series of required schedules which provide detailed information on items such as existing generating facilities, energy consumption and number of customers, summer and winter peak demand history and forecasts, net energy for load (NEL) history and forecast, etc. This information provides the basis for the Commission's review. Additional data is obtained through supplemental data requests.

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 entire state.[3] In addition to the *2011 Regional Load and Resource Plan*, the Commission used the FRCC's *2011 Reliability Assessment* as a resource in the production of this review.

On September 7, 2011, the Commission held a public workshop to facilitate discussion of the annual planning process. In addition to a presentation by the FRCC, presentations were given by FPL, PEF, and TECO in order to highlight the significant aspects of the 2011 TYSPs for these utilities. The workshop also allowed for public comment on any of the TYSPs that were filed with the Commission.

**Suitability**

The Commission has reviewed the Ten-Year Site Plans 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. Therefore, the Commission finds the 2011 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes.

Since the Ten-Year Site Plan 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 Ten-Year Site Plan at a public hearing.

[3] Peninsular Florida refers to the FRCC region, which includes all Florida utilities except Gulf Power Company.

# STATEWIDE PERSPECTIVE

## FLORIDA'S POPULATION AND ELECTRICITY FORECASTS

Table 2 illustrates the breakdown of the customer base in Florida and the amount and percentages of electric energy purchased by each class.

**Table 2. State of Florida: Characteristics of Florida's Electric Customers (2010 Actual)**

| Customer Class | Number of Customers | % of Customers | Energy Sales (GWh) | % of Sales |
|---|---|---|---|---|
| Residential | 8,324,256 | 88.7% | 118,870 | 54.1% |
| Commercial | 1,030,955 | 11.0% | 80,182 | 36.5% |
| Industrial | 27,043 | 0.3% | 20,708 | 9.4% |
| **Total** | **9,382,254** | **100.0%** | **219,760** | **100.0%** |

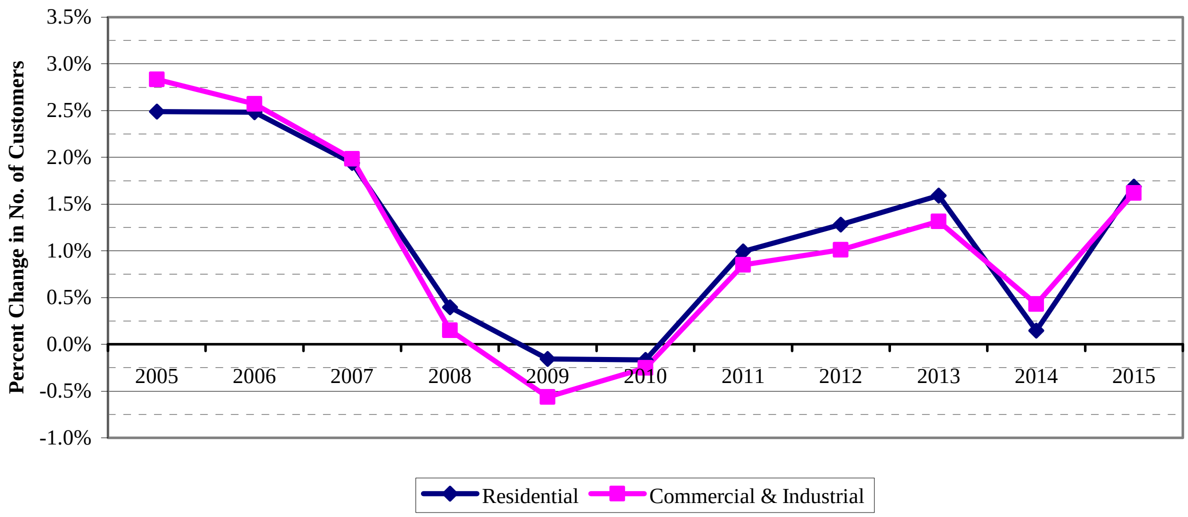
Source: FRCC's 2011 Load & Resource Plan, p. S-2

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 energy and demand. Utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs.

The numbers of customer accounts declined each year from 2005 through 2009. This trend was presumably a consequence of the economic recession being experienced across the nation and the high numbers of foreclosures in Florida. However, in 2010 the growth in commercial customers became positive once again, although at a much lower rate than historic norms, while the growth in residential accounts was stable.

Figure 1 shows the actual annual growth rate for the period 2005 through 2010, as well as the forecasted growth rate from 2011 through 2015. Beginning in 2005, the growth rate in the numbers of customers began to slow, and in 2009 and 2010 was actually negative. Although the rate of growth in 2010 was still negative, it had stabilized. In the first part of 2011 the numbers of customer accounts began to increase, and positive growth is forecasted to continue each year (except for 2014) throughout the planning horizon. In conjunction with this trend, the per customer consumption for residential accounts spiked upwards. The cause of this spike could be related to the economic recession, as a result of having more occupants per household. The number of customer accounts appears to drop in the 2014 plan year, due to a decrease in customers for both FMPA (when the City of Lake Worth leaves the ARP) and SEC (when the Lee County Electric Cooperative will no longer be served).

**Figure 1. State of Florida: Annual Growth Rate (%) of Customers for 2005 through 2015**



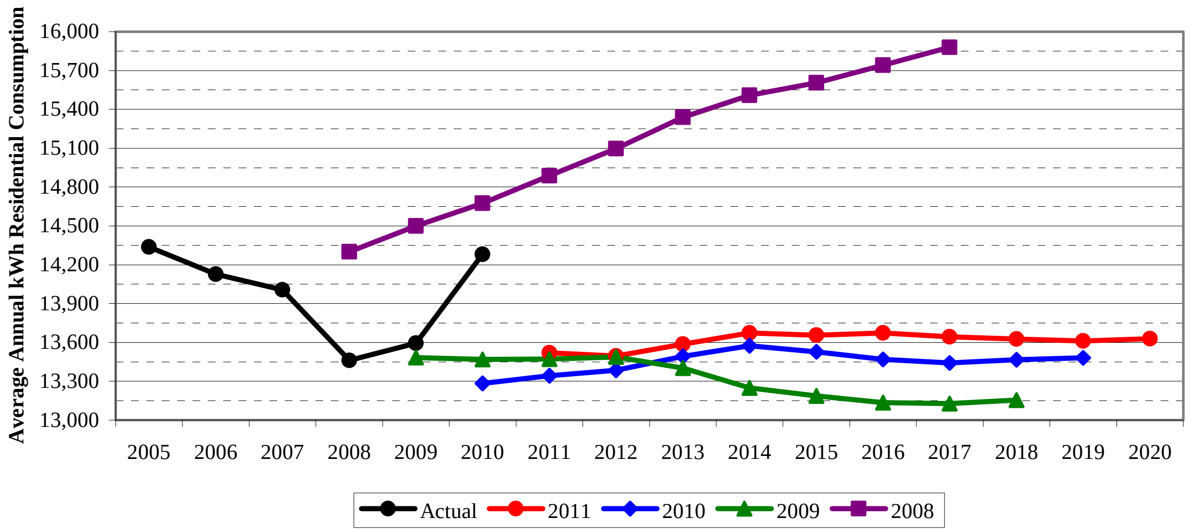

Source: FRCC's 2011 Load & Resource Plan, p. S-2

Florida's electrical demand and energy requirements are heavily dependent on the energy consumption behaviors of residential customers. This relationship is a result of the fact that close to 90 percent of electric customers in Florida are residential accounts, with these customers purchasing more than half the energy sold in the state in 2010.

The 2011 Ten-Year Site Plans have two major differences from the Plans produced in the years since 2005. The annual growth rate of customers has become positive, and the energy consumption per residential customer has risen to a level well above that which was forecasted in the two previous planning cycles.

Per customer energy consumption is a major contributor in the utilities' determination of net energy for load (NEL). Figure 2 shows the actual per customer consumption from 2005 through 2010, as well as changes in the forecasted energy usage since 2008. Actual usage began to increase in 2009 after three years of decline, and therefore the forecasted per customer consumption has been adjusted slightly upward each year following the dramatic drop in forecasted usage in 2009. Both Figures 1 and 2 appear to indicate that the electric industry in Florida is beginning a return to patterns of growth which are more consistent with historic levels.

**Figure 2. State of Florida: Average Energy Consumption per Residential Customer**

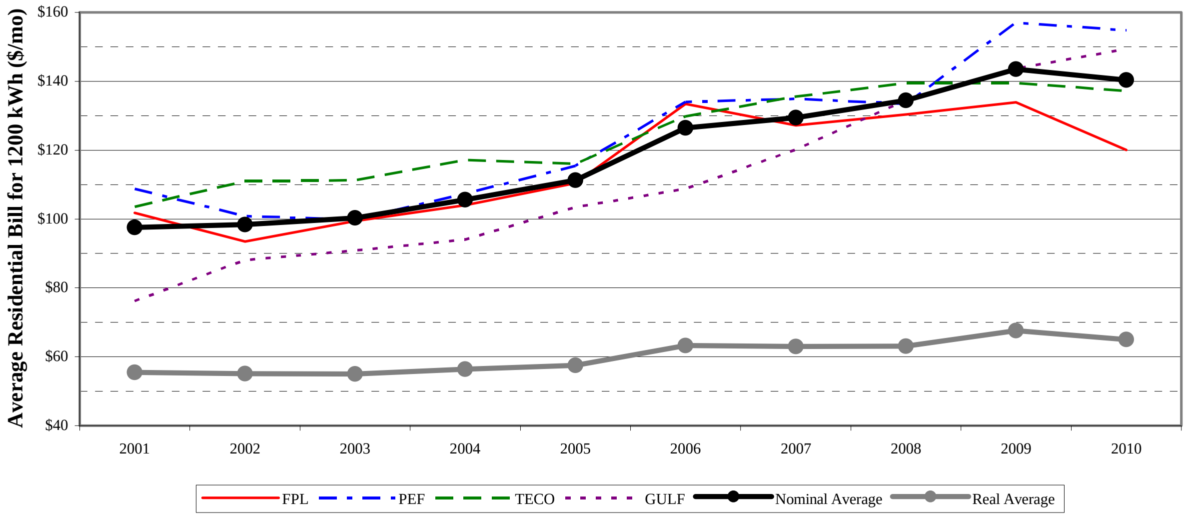



Source: FRCC's 2011 Load & Resource Plan, S-2

As Figure 3 illustrates, the average bill for a residential electric customer in Florida has increased steadily since 2001. In the 20 years prior to 2001, electricity prices were held at a relatively stable level due to moderate fuel prices and a balanced fuel supply. However, Florida's increasing reliance on natural gas for electric generation, coupled with a rise in the price of natural gas nationally, has led to a consistent increase in the average residential monthly bill over the past ten years. A slight decline in the average bill for 2010 can be seen in Figure 3, which is an indication that fuel prices dropped relative to usage. This result is expected since residential bills are based mostly on energy consumption, as opposed to commercial and industrial accounts which are based on both energy and maximum demand. The average bills are shown in both real and nominal amounts.[4]

[4] Nominal values are expressed in current dollars, while real values have been adjusted for the effects of inflation.

**Figure 3. IOUs: Average Residential Monthly Bill (2001 to 2010)**




Source: Responses to FPSC Data Requests.

## Seasonal Peak Demand and Energy Forecasts

Historical data such as energy usage patterns, trends in population growth, economic variables, and weather data form the foundation for each utility's load and energy forecasts. Econometric forecast models are then used to quantify the historical impact of these data, and together with sets of forecast assumptions on future growth, energy usage, and weather for each utility's service territory, the final demand and energy forecasts are produced. These peak demand and energy forecasts are used as the starting point for determining new capacity additions necessary to maintain minimum levels of reliability.

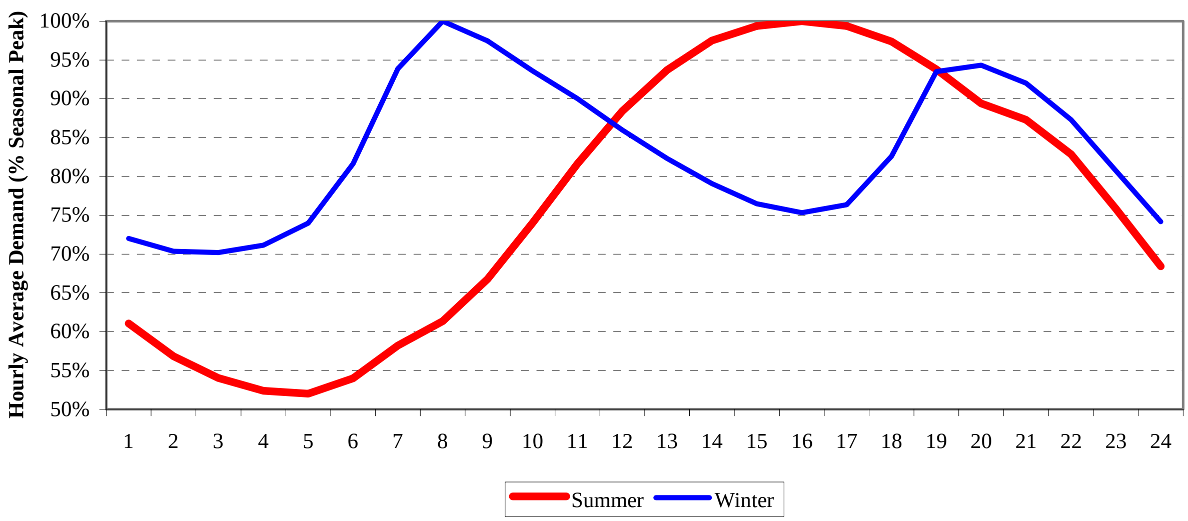
Peak demand is a measure of the amount of electric power required at any particular instant in time, and is measured in megawatts (MW). These very important quantities are determined for both the summer and winter seasons, and the maximum values are used in the determination of the timing and size of future capacity additions. Energy is the accumulation of demand over time, and its unit of measure is the megawatt-hour (MWh), which is the total amount of MW consumed over a one-hour period of time.[5] For example, if a device uses one MW and it is operated for one hour, then the total energy consumption is one MWh. The appropriate type of new generating capacity required is determined by energy requirements of the system. A load that remains relatively constant would require a base load unit, whereas a load with a great deal of variation would require a peaking or intermediate unit. However, a utility must take many factors into consideration when planning both the type of generation and the fuel that best suit the circumstances.

Because the vast majority of customers in Florida are residential, peak demand in the summer season begins to climb in the morning, peaks during the hottest part of the day, and

[5] Alternate units of energy are the kilowatt-hour (kWh) and the gigawatt-hour (GWh). A kilowatt is one thousand watts ($10^3$ watts), a megawatt is one million watts ($10^6$ watts), and a gigawatt is one billion watts ($10^9$ watts).

levels off as the evening approaches. This usage pattern corresponds to increasing loads due to air conditioning for residential customers. In the winter season, the usage pattern has two distinct peaks: the larger one in the mid-morning and a smaller one in the late evening, which correspond to residential heating loads. Figure 4 illustrates the daily load curve for a typical utility in Florida.

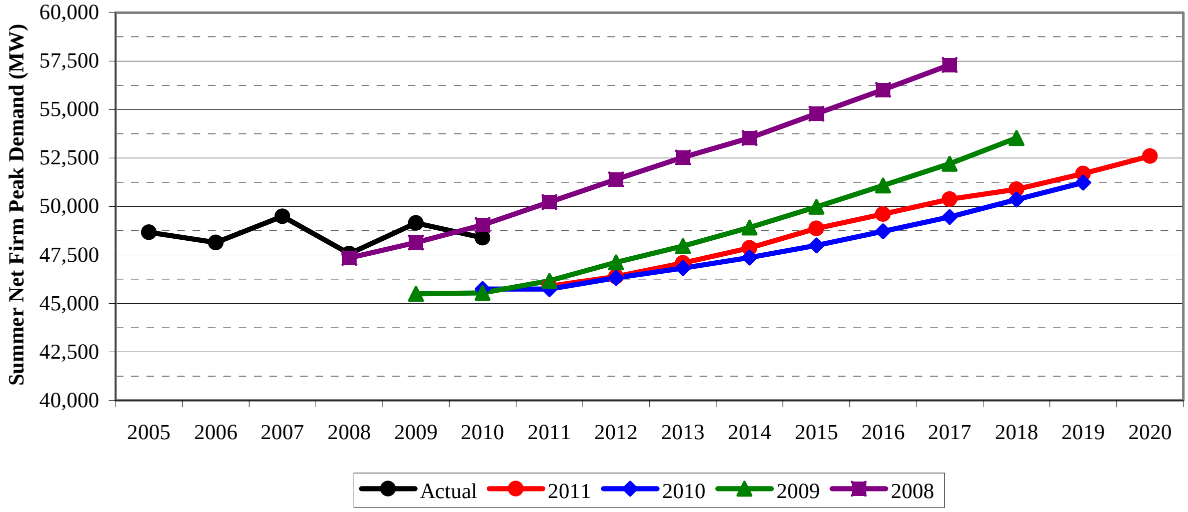
**Figure 4. Typical Daily Load Curve for Florida Electric Utility**




Source: Responses to FPSC Data Requests.

Because Florida has historically experienced its highest electric demand during summer months, the timing of future capacity additions will be based mainly on the projected summer peak demand. As Figure 5 shows, utilities in Florida adjusted their forecasts for summer peak demand downward in 2009 and in 2010, but in 2011 it was adjusted slightly upward. This change is in accordance with the positive changes in customer accounts as well as forecasted per customer consumption for the current planning horizon.

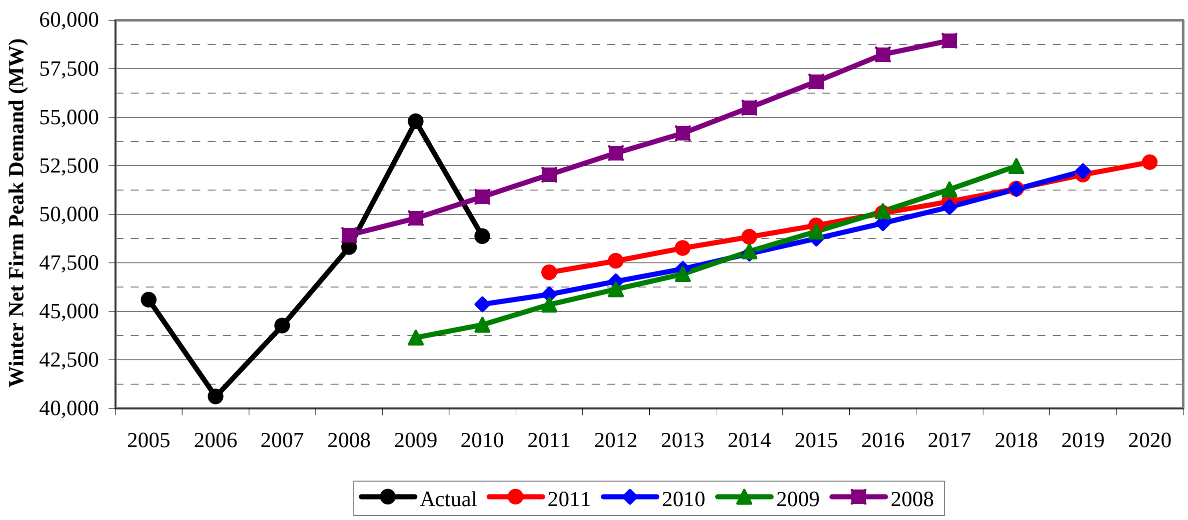
**Figure 5. State of Florida: Summer Demand (Actual and Forecasted)**




Source: FRCC's 2008 to 2011 Load & Resource Plans

Figure 6 shows the actual and forecasted winter peak demand. As with summer peak demand, the forecast for winter peak demand was adjusted downward in 2009. However, in 2010 the forecast was adjusted slightly upward in the early years, and downward in the later years of the planning horizon. This same adjustment was made in the current forecast, causing the winter demand forecast to become more level. The winter peak demand actual values were quite a bit higher than was forecasted for these same years, most likely due to the cold snaps in the past two winter seasons that produced record or near-record low temperatures.

**Figure 6. State of Florida: Winter Demand (Actual and Forecasted)**

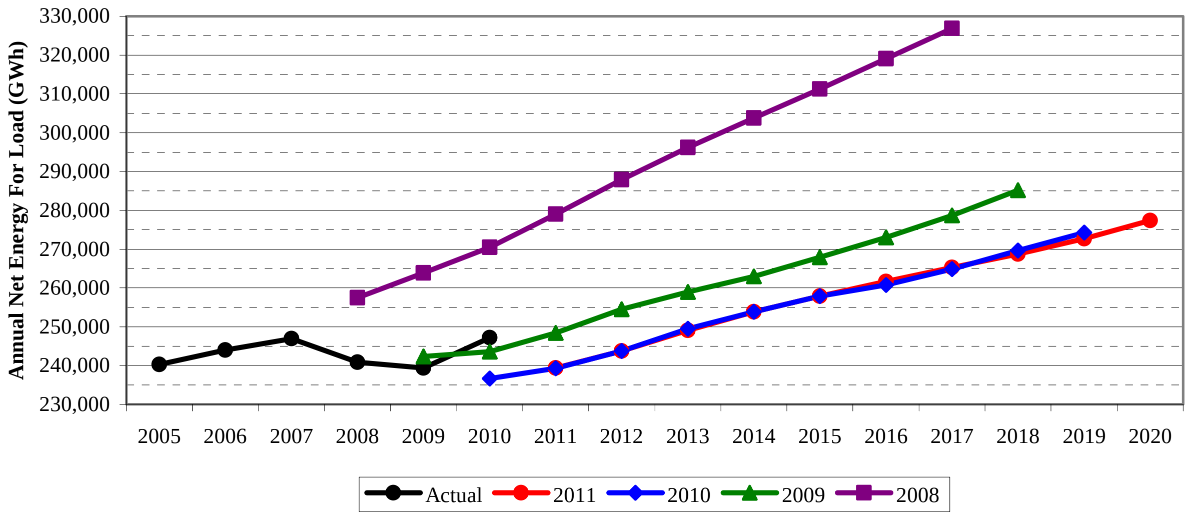



Source: FRCC's 2008 to 2011 Load & Resource Plans

Net energy for load (NEL) represents the amount of energy necessary to meet customer's needs. Figure 7 illustrates the actual and forecasted annual values for NEL. As discussed previously, NEL determines the type of generation that will be required (base load, peaking, or intermediate).

The actual values for NEL in 2009 and 2010 are quite close to the 2009 forecast, as can be seen from Figure 7. Although the forecasts for 2010 and 2011 are nearly identical, both are below the 2009 forecast, and all three are well below the levels forecasted in 2008.

**Figure 7. State of Florida: Annual Net Energy for Load (Actual and Forecasted)**




Source: FRCC's 2008 to 2011 Load & Resource Plans

Because the effects of forecast error can be dramatic, the Commission compares the forecasts to historical values for peak load and energy. Reviewing the past results of a load and energy forecasting methodology reveals whether that methodology has produced accurate forecasts. A pattern of over- or under-forecasting is indicative of past forecast error that could be carried forward into current forecasts.

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 2006 to 2010. The review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2006 energy sales were compared to the projected 2006 forecasts made in 2001, 2002, and 2003. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy. When the individual utilities' error rates are averaged together, the resulting average forecast error is 2.44 percent. This value indicates that overall, the eleven utilities filing TYSPs have tended to over-forecast their energy sales by 2.44 percent. If the tendency was to under-forecast, the error rate would be a negative value.

## RELIABILITY CRITERIA

In order to ensure the reliability of the nation's electrical systems, the Federal Energy Regulatory Commission (FERC) in 2006 certified the North American Electric Reliability Corporation (NERC) to be the electric reliability organization with statutory authority to enforce compliance with reliability standards among all market participants in the U.S. In turn, NERC has authorized the Florida Reliability Coordinating Council (FRCC) to implement a compliance program to monitor and enforce reliability standards within Peninsular Florida.[6] Among many others, one important standard that Florida's electric utilities must meet is a minimum level of reserve capacity, also called a reserve margin.

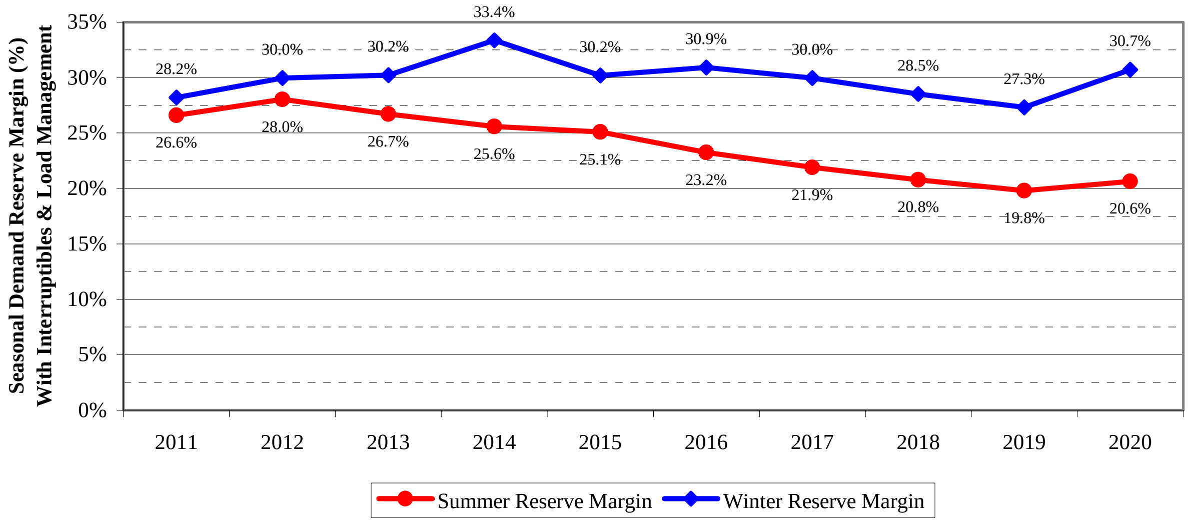
In order to maintain stability in the electric system, utilities must constantly adjust system output to match demand from moment to moment. As demand fluctuates, utilities must generate the precise amount of electrical power that will keep the system in balance. In addition, utilities must be prepared at any moment to meet unexpected spikes in demand due to unforeseen circumstances, such as extreme weather events. Although peak demand is methodically forecasted and carefully monitored, each utility must maintain a certain amount of "extra" or reserve capacity in the event that demand rises above 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.

Figure 8 is a graphical representation of the aggregate reserve margin for Peninsular Florida's electric utilities over the current planning horizon. Because Gulf uses a different method to calculate its reserve and is not affiliated with the FRCC, the figure does not include Gulf. The values in the figure include both supply-side and demand-side contributions.

[6] Gulf Power Company, the only TYSP utility that is not part of Peninsular Florida, is affiliated with SERC, another electric reliability organization authorized by NERC.

**Figure 8. FRCC: Peninsular Reserve Margin Projections**




Source: FRCC's 2011 Load & Resource Plan, p. 29

## DEMAND-SIDE MANAGEMENT

In recent years, the standards for appliance efficiency and building codes have gradually been increased in Florida in order to maximize energy savings. However, the responsibility for reducing the state's dependence on fossil fuels and improving the environment falls largely on consumers. Encouraging consumers to make responsible choices is extremely important in controlling load and energy usage. Customers that are made aware of energy-saving behaviors which can result in reduced energy use and lower bills are much more likely to participate in utility-sponsored DSM and conservation programs.

Demand-side management reduces peak demand and energy requirements, resulting in the deferral of need for new generating units. Utilities have made DSM programs available to customers since 1980, based on the requirements of the Florida Energy Efficiency and Conservation Act (FEECA).[7] FEECA emphasizes reducing the growth rates of weather-sensitive peak demand, reducing and controlling the growth rate of electricity consumption, reducing the consumption of scarce resources such as petroleum fuels, and encouraging use of renewable fuels. To meet these objectives, FEECA requires that the Commission establish conservation and DSM goals and requires all IOUs and all municipal and cooperative utilities with annual energy sales of at least 2,000 GWh as of July 1, 1993, to implement DSM programs to meet the goals established by the Commission. The seven utilities in Florida subject to FEECA are FPL, FPUC, Gulf, JEA, OUC, PEF, and TECO.[8] The Commission regulates electric utility conservation measures and programs pursuant to Rules 25-17.001 through 25-17.015, F.A.C.

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[7] Sections 366.80-366.85 and 403.519, F.S.

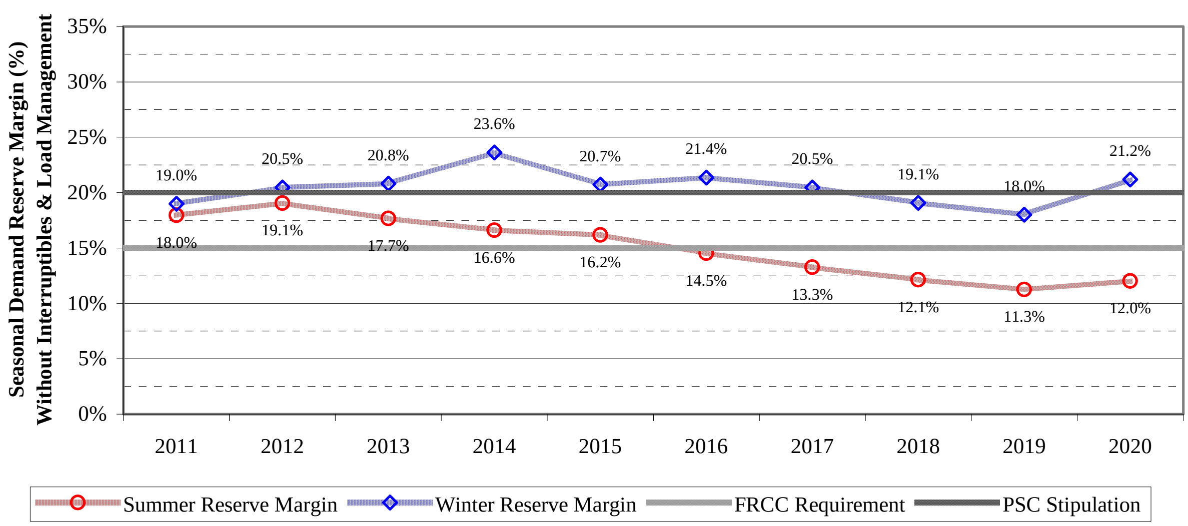
[8] Florida Public Utilities Company (FPUC) is subject to FEECA requirements because it is an IOU, but it is not required to file a Ten-Year Site Plan with the Commission because it does not generate electrical energy.

Before a utility can be granted a determination of need to build new supply-side generation, it must demonstrate to the Commission that it has maximized all possible demand-side resources, including both conservation (or energy efficiency) and load management programs. Load and energy savings from conservation or non-dispatchable DSM programs, such as ceiling insulation installation, enable utilities and customers to realize sustained energy savings over time. Dispatchable DSM, such as load management and interruptible load programs, are measures that allow reductions in system peak demand when needed. Monetary incentives are offered in exchange for the utility's control over the availability of certain appliances for residential customers, or the interruption of specific services to a commercial or industrial customer.

Figure 9 illustrates the impact of DSM on the aggregate reserve margin for Florida's electric system. It is clear that DSM plays a crucial role in the provision of reserve capacity. Utilities may choose to maintain a minimum generation-only reserve margin, due to the fact that most DSM programs are strictly voluntary. Because the system reliability for Florida's utilities are becoming increasingly dependent on DSM, some utilities have or are considering a minimum generation-only level of reserve capacity.

**Figure 9. FRCC: Peninsular Reserve Margin Projections Without Load Management**

20 Percent: PSC Stipulation 15 Percent: FRCC Criteria




Source: FRCC's September 7, 2011 TYSP Workshop Presentation, slide 10

All of the utilities have prepared their 2011 Ten-Year Site Plans incorporating the goals set by the Commission in December 2009, and all utilities except FPL and PEF have had DSM plans based on those goals approved by the Commission. In July 2011, the Commission found that the DSM Plans based on the 2009 goals filed by both FPL and PEF would have an undue impact on the costs passed on to consumers, and that the public interest would be served by requiring modifications to those Plans. Therefore, the Commission modified the Plans of FPL and PEF, such that the DSM Plans of both utilities consist of those programs that were already in effect.[9]

[9] Orders No. PSC-11-0346-PAA-EG in Docket No. 100155-EG, and PSC-11-0347-PAA-EG in Docket No. 100160-EG, issued August 16, 2011.

# RENEWABLE ENERGY

## Federal Legislation

In 1978, the U.S. Congress enacted the Public Utility Regulatory Policies Act (PURPA)[10]. PURPA endorsed three broad national purposes: (1) conservation of electric energy, (2) increased efficiency in the use of facilities and resources by electric utilities, and (3) equitable rates for electricity consumers. Section 210 of Title II, entitled "Cogeneration and Small Power Production," required electric utilities to interconnect and sell electric energy to qualifying cogeneration and small power production facilities, referred to as Qualifying Facilities, or QFs, and to purchase electric energy from these facilities at the utility's full avoided cost. The Federal Energy Regulatory Commission (FERC) subsequently adopted rules to implement PURPA. In addition, states were delegated authority to implement the FERC rules for electric utilities over which they have rate making authority.[11] In 1980, the FERC issued its rules establishing the criteria for determining the qualifying status of a facility and setting out regulations for electric utility interconnection with QFs, along with sales to and purchases from QFs.[12]

## State Legislation

In 1981, the Florida Legislature authorized the Commission to establish guidelines for the purchase and sale of capacity and energy from cogenerators and small power producers, which includes renewable generators. In 1989, the statutes were broadened with the enactment of Section 366.051, F.S., which provides, in part, the following:

> Electricity produced by cogeneration and small power production is of benefit to the public when included as part of the total energy supply of the entire electric grid of the state or consumed by a cogenerator or small power producer. The electric utility in whose service area a cogenerator or small power producer is located shall purchase, in accordance with applicable law, all electricity offered for sale by such cogenerator or small power producer; or the cogenerator or small power producer may sell such electricity to any other electric utility in the state. The Commission shall establish guidelines relating to the purchase of power or energy by public utilities from cogenerators or small power producers and may set rates at which a public utility must purchase power or energy from a cogenerator or small power producer. In fixing rates for power purchased by public utilities from cogenerators or small power producers, the Commission shall authorize a rate equal to the purchasing utility's full avoided costs. 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.

[10] Public Law 95-617 (HR 4018) November 9, 1978.
[11] PURPA at Title II, section 210(f); In Florida, the Florida Public Service Commission has ratemaking jurisdiction over five investor-owned electric utilities: Florida Power & Light Company (FPL), Progress Energy Florida (PEF), Gulf Power Company (Gulf), Tampa Electric Company (TECO), and Florida Public Utilities Company (FPUC).
[12] 18 C.F.R. 292.101 through 18 CFR 292.602.

In 2005, the Legislature enacted Section 366.91, F.S., which requires investor-owned utilities to continuously offer purchase contracts to producers of renewable energy, and adopts the avoided cost standard as defined in Section 366.051, F.S. Section 366.91, F.S., also defines the term "renewable energy" 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. The term 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.

**Commission Rules**

Renewable facilities are permitted to enter into two types of contractual agreements for selling power: standard offer and negotiated contracts. Under these contracts, the energy can be sold as either "firm" or "as-available," depending on the characteristics of the output of the facility. When the output is continuous, except for occasional shutdowns for maintenance and repair, the utility also makes payments for the dependable capacity. These contract and payment options are outlined in Rule 25-17.0825 and Rule 25-17.0832, F.A.C.

*Standard Offer Contracts*

Standard offer contracts are pre-approved contracts for the purchase of firm capacity and energy from any renewable generating facility or small qualifying facility. Rule 25-17.230, F.A.C., requires each investor-owned electric utility to establish a standard offer contract for each fossil-fueled generating unit type identified in the utility's Ten-Year Site Plan. The renewable energy generator is allowed to select from a number of payment options that best fits its financing requirements as long as the total cumulative present value of such payments do not exceed full avoided cost, and adequate security for front-end loaded payments is provided. For example, the Commission rules allow for levelized payments over the life of the contract which may include both capacity and energy costs.

*Negotiated Contracts*

Renewable generating facilities are encouraged to negotiate purchased power contracts with investor-owned electric utilities pursuant to Rule 25-17.240, F.A.C. Payments made to a qualified renewable generator under a negotiated contract may be recovered from ratepayers by the purchasing utility as long as the cumulative present value of the payments do not exceed the utility's full avoided cost and adequate security for front-end loaded payments is provided.

**Renewable Payment Types**

*Firm capacity payments:* Firm capacity is capacity (MW) produced and sold by a renewable energy generator pursuant to a standard offer contract or a negotiated contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Firm capacity is purchased at a rate specified in a contract which is equal to the utility's avoided capacity cost or at a negotiated rate which may not exceed the utility's avoided capacity cost. Full avoided cost is calculated by determining the cumulative present value of a year-by-year value of deferring each avoided unit over the term of the contract.

*Firm energy payments:* Firm energy is energy (kWh) produced and sold by a renewable energy generator pursuant to a negotiated contract or a standard offer contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Generally, the rate of payment for firm energy, in cents per kWh, is the lesser of the fuel cost associated with the avoided unit or the utility's system decremental fuel cost.

*As-available energy payments:* As-available energy is energy (kWh) produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required. As-available energy is purchased at a rate in cents per kilowatt hour (kWh) equal to the utility's hourly decremental system fuel cost, which reflects the highest fuel cost of generation dispatched each hour. No capacity payments are made for as-available energy because no reliability benefits are received.

**Renewable Resource Outlook**

In 2003, the Commission, in consultation with the Florida Department of Environmental Protection (FDEP), completed the 2003 Renewable Energy Assessment Report to identify renewable energy viability in Florida. According to the report, the most feasible sources of renewable energy in Florida are from biomass materials, such as agricultural waste products or wood residues, and industrial waste heat. The 2003 report also stressed that technical feasibility does not ensure economic cost-effectiveness when determining energy resource production.

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. to prepare a detailed assessment of Florida's renewable potential. The 2008 Navigant Consulting Renewable Energy Potential Assessment (the 2008 Navigant Consulting Report) reported on the existing renewable conditions and the projected potential for renewable development in Florida through 2020, compared cost-effective differences, and considered the potential levels of economic impact future renewables may have. The 2008 Navigant Consulting Report substantiated the Commission's 2003 assessment by observing that the majority of Florida's existing renewables consist of solid biomass plants and municipal solid waste facilities. Although the 2008 Navigant Consulting Report considered solar technologies to have the largest technical potential of any renewable resource in Florida, only a portion of this potential can actually be economically achieved at this time.

The 2008 Navigant Consulting Report described the comparison of the technical or physical potential versus the achievable potential for renewable energy development in Florida. For example, although the technical potential for solar power in Florida may be relatively high according to Navigant Consulting, cost-effectiveness and siting issues significantly reduce the achievable potential to commercially develop solar energy technology. The driving forces to the expansion and sustainability of the renewable market depend on the overall value of renewable energy, a basis that is determined by the financial environment as well as government regulation and support. As noted in the 2008 Navigant Consulting Report, a favorable scenario for the renewable market which has meaningful growth in Florida assumed the following:

1. High fossil fuel costs
2. Access to low cost capital and debt rates
3. Continual government rebate programs and tax incentives
4. Established pricing of $CO_2$ emissions
5. Formation of a Renewable Energy Certificate (REC) market

Since the 2008 Navigant Consulting Report was completed, economic and policy conditions have generally coincided with the unfavorable scenario for future renewable development. Specifically, Navigant Consulting assumes natural gas costs to be $5-$6/MMBtu in the unfavorable scenario. Natural gas is currently trading at approximately $4.20/MMBtu. Most forecasts project natural gas prices to increase over the long term. In the unfavorable scenario, the cost of debt was estimated to be approximately 8.5 percent, the cost of equity approximately 14 percent, and ready access to debt would make up 50 percent of renewable project financing. Credit markets are still tight for small businesses, and obtaining financing for renewable energy projects will be much more difficult for a smaller company than for a large utility. In the unfavorable scenario, Navigant Consulting estimated that Florida's solar rebate program would expire in 2010, with a $5 million annual funding level. The Florida Energy and Climate Commission was authorized to provide $25.4 million in rebates for solar energy equipment between 2006 and 2009. Currently the authorized budget has been depleted. Also, the unfavorable scenario for carbon pricing assumes $0/ton initially, then scaling to $10/ton by 2020. Currently, there is no federal or state policy establishing carbon pricing. Finally, no Renewable Energy Credit (REC) market has yet been established in Florida.

## EXISTING RENEWABLE RESOURCES

Currently, renewable energy facilities provide approximately 1,300 MW of electric generation capacity, which represents 2.3 percent of Florida's overall generation capacity of 57,605 MW in 2011.[13] Pursuant to current state and federal law, payments made by utilities to generation facilities using renewable energy sources are capped at the utility's avoided cost for capacity and energy. Compared to figures in the 2010 Ten-Year Site Plan Review, existing renewable generation facilities have grown by approximately 6.82 percent (83.2 MW). Table 3 summarizes Florida's existing renewable resources.

[13] Total MW capacities are based on summer ratings.

**Table 3. State of Florida: Existing Renewable Resources**

| Fuel Type | Capacity (MW) |
|---|---|
| Solar | 112.4 |
| Wind | 0.0 |
| Biomass | 379.4 |
| Municipal Solid Waste | 408.6 |
| Waste Heat | 285.9 |
| Landfill Gas | 52.6 |
| Hydro | 43.5 |
| **Total** | **1282.4** |

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

## Firm Capacity Contracts

Almost 30 percent of all renewable capacity in Florida is from firm capacity contracts, which are required to provide a particular amount of capacity for a specified period of time pursuant to contractual obligations. Approximately 79 percent of these firm contracts are with municipal solid waste (MSW) facilities. The remainder of firm capacity generation is from third-party landfill and woody biomass gas production facilities. Although the majority of firm capacity is purchased by investor-owned utilities, a significant portion (112.8 MW) is purchased by Seminole Electric Company (SEC).[14] Table 4 lists the existing contracts for firm capacity from renewable generation units.

The acronyms for renewable fuel types used in the following tables are defined below:

AB: Biomass—agricultural byproducts

LFG: Landfill gas

MSW: Municipal Solid Waste

OBG: Biomass—gases (other than landfill gas)

SUN: Solar

WAT: Hydro (water)

WDS: Biomass—wood waste solids

WH: Waste Heat

[14] Seminole Electric is a rural electric cooperative utility providing generation and transmission services to 13 member distribution cooperatives in peninsular Florida.

**Table 4. State of Florida: Contracts for Firm Renewable Energy**

| Purchasing Utility | Facility Name | Fuel Type | Contracted Firm Capacity (MW) | Commercial In-Service Date |
|---|---|---|---|---|
| **Investor-Owned Utilities** | | | | |
| FPL | Broward-North | MSW | 11.0 | 1992 |
| FPL | Broward-South | MSW | 3.5 | 1991 |
| FPL | Palm Beach County | MSW | 50.0 | 2005 |
| PEF | Dade County Resource Recovery | MSW | 43.0 | 1991 |
| PEF | Lake County Resource Recovery | MSW | 12.8 | 1990 |
| PEF | Pasco County Resource Recovery | MSW | 23.0 | 1991 |
| PEF | Pinellas County Resource Recovery | MSW | 54.8 | 1983 |
| PEF | Ridge Generating Station | WDS | 39.6 | 1994 |
| TECO | City Of Tampa Refuse-To-Energy | MSW | 21.0 | 1985 |
| | **Subtotal of IOUs** | | **258.7** | |
| **Municipal Utilities** | | | | |
| GRU | G2 Energy | LFG | 3.8 | 2008 |
| JEA | Trailridge | LFG | 9.0 | 2008 |
| | **Subtotal of Municipals** | | **12.8** | |
| **Cooperative Utilities** | | | | |
| SEC | Brevard Energy | LFG | 9.0 | 2008 |
| SEC | Seminole Landfill | LFG | 6.2 | 2007 |
| SEC | Timberline Energy | LFG | 1.6 | 2008 |
| SEC | Lee County Resource Recovery | MSW | 45.0 | 1999 |
| SEC | Telogia Power, LLC | WDS | 13.0 | 2004 |
| SEC | Hillsborough Waste to Energy | MSW | 38.0 | 2010 |
| | **Subtotal of Cooperatives** | | **112.8** | |
| | **Total** | | **384.3** | |

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

Significant changes in the firm contracts since 2010 include the formerly firm 95.5 MW from the Broward-North and Broward-South facilities to be sold as non-firm energy to FPL. Also, the energy and capacity sold by Hillsborough Waste to Energy Facility was transferred from FPL to SEC. Additionally, SEC is expected to negotiate a contract with the City of Tampa Refuse-To-Energy Facility to purchase 19.0 MW following the expiration of the existing contract with TECO in August of 2011.

### Non-Firm Renewable Energy Generators

In addition to the 384 MW of firm capacity described in Table 4 above, renewable energy facilities also produce about 732 MW of non-firm capacity for sale to utilities on an as-available basis. Energy purchased on an as-available basis is considered non-firm capacity, and therefore cannot be counted on by Florida's utilities for reliability purposes. The energy produced by these providers, however, do contribute to the avoidance of burning fossil fuels in existing generators. Table 5 details the various non-firm energy contracts.

**Table 5. State of Florida: Non-Firm Renewable Energy Generators**

| Purchasing Utility | Facility Name | Fuel Type | Non-Firm Capacity (MW) | Commercial In-Service Date |
|---|---|---|---|---|
| **Investor-Owned Utilities** | | | | |
| FPL | MMA FLA LP | SUN | 0.3 | 2007 |
| FPL | Georgia Pacific | WDS | 52.0 | 1983 |
| FPL | New Hope / Okeelanta | AB | 140.0 | 1985 |
| FPL | Tomoka Farms | LFG | 3.8 | 1998 |
| FPL | WM Renewable Energy | LFG | 8.0 | 2010 |
| FPL | Broward South | MSW | 50.5 | 2009 |
| FPL | Broward North | MSW | 45.0 | 2011 |
| GULF | Bay County Solid Waste | MSW | 11.0 | 2008 |
| GULF | Stone Container* | AB | 25.0 | 1960 |
| GULF | International Paper Company* | WDS | 43.0 | 1983 |
| PEF | TMC* | WDS | 38.0 | 2006 |
| PEF | Potash Of Saskatchewan* | WH | 42.0 | 1986 |
| TECO | South Pierce* | WH | 23.0 | 1969 |
| TECO | New Wales* | WH | 65.0 | 1984 |
| TECO | CF Industries* | WH | 34.9 | 1988 |
| TECO | Ridgewood* | WH | 77.0 | 1992 |
| TECO | Millpoint* | WH | 44.0 | 1995 |
| TECO | City of Tampa Sewage | OBG | 1.5 | 1989 |
| | **Subtotal of IOUs** | | **704.0** | |
| **Municipal Utilities** | | | | |
| FMPA | US Sugar Corporation | AB | 26.5 | 1984 |
| GRU | Solar FIT Program/Net Meter | SUN | 1.5 | 2009 |
| LAK | Lakeland Center (Solar) | SUN | 0.3 | 2010 |
| | **Subtotal of Municipals** | | **28.3** | |
| | **Total** | | **732.3** | |

* These facilities represent partial or full generation for self-service purposes only. The self-service portion of the facilities do not generate energy to be put on the grid, but are still considered for renewable energy generation in a local level.

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

## Existing Utility-Owned Renewable Facilities

Several utilities also own renewable facilities, utilizing a wide range of technologies. Table 6 lists some of the larger utility-owned resources, which consist mostly of non-firm or intermittent resources.

**Table 6. State of Florida: Existing Utility Owned Renewable Generation**

| Utility | Facility Name | Fuel Type | Capacity (MW) | Commercial In-Service Date |
|---|---|---|---|---|
| **Investor-Owned Utilities** | | | | |
| FPL | DeSoto | SUN | 25.0 | 2009 |
| FPL | Martin | SUN | 75.0 | 2010 |
| FPL | Space Coast Next Generation | SUN | 10.0 | 2010 |
| GULF | Perdido 1 | LFG | 1.5 | 2010 |
| GULF | Perdido 2 | LFG | 1.5 | 2010 |
| Various | Distributed Solar Installations (Aggregate) | SUN | 0.1 | Varies |
| | **Subtotal of IOUs** | | **113.1** | |
| **Municipal Utilities** | | | | |
| JEA | North Landfill* | LFG | (gas sub. only) | 1997 |
| JEA | Girvin Landfill | LFG | 1.2 | 1999 |
| JEA | Buckman | OBG | 0.8 | 2003 |
| OUC | Co-Fired Stanton Energy Center | LFG | 7.0 | 1998 |
| TAL | Corn Hydro | WAT | 0.0 | 1985 |
| Various | Distributed Solar Installations (Aggregate) | SUN | 0.2 | Varies |
| | **Subtotal of Municipals** | | **9.2** | |
| **Other Utilities** | | | | |
| UCEM | Jim Woodruff | WAT | 43.5 | 1957 |
| | **Subtotal of Others** | | **43.5** | |
| | **Total** | | **165.8** | |

* The North Landfill facility does not generate electricity, but provides a partial fuel substitute for nearby natural-gas unit generation.

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

Because most of the energy produced is non-firm, the majority of these renewable facilities serve more to reduce fossil fuel consumption than to provide system capacity. Among some of the recent notable additions to utility-owned renewables are the construction and operation of three solar generators by FPL. The DeSoto, Martin, and Space Coast facilities are the largest solar facilities in Florida.[15] Gulf Power has recently commissioned two landfill gas generation facilities, Perdido 1 and 2, to provide that utility with a total of 3.0 MW of firm energy and capacity.

## Self-Service Facilities

In addition to the facilities detailed above, which provide renewable energy to the transmission grid through contracts or as-available energy tariffs, several self-service facilities also produce energy from renewable resources. Firms with facilities such as these do not deliver

[15] The DeSoto and Space Coast facilities are direct energy-producing photovoltaic facilities, whereas the Martin facility uses thermal heat to create replacement steam for a pre-existing steam turbine usually supplied through fossil fuel generation.

energy to the grid, but rather use the renewable energy produced to meet or reduce their own energy requirements. Like non-firm renewables, these facilities cannot be counted on for reliability purposes, but they do still contribute to the reduction of Florida's dependence on fossil fuel-fired generation.

### Existing Net Metering

Net metering is an arrangement between a utility and a customer with renewable generation capability whereby the customer's energy usage is offset by the amount of energy generated. The net meter keeps account of the amount of energy generated and the amount consumed, and if the energy consumed by the customer is less than that produced by the renewable generator, then the utility will credit the customer's account for the excess amount of energy produced. Conversely, the customer will be billed for any net energy consumed that exceeds the energy generated.

In April 2008, the Commission amended Rule 25-6.065, F.A.C., on interconnection and net metering for customer-owned renewable generation. The rule 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. Customers first benefit from such renewable systems by reducing their energy purchases from the utility. Net metering provides an additional benefit by allowing customers with excess renewable energy production to reduce future energy purchases from the utility.

The Commission's rule requires all electric utilities to annually report data associated with interconnection and net metering programs. Data submitted in April 2010 show that the number of customers owning renewable generation systems in Florida continues to grow. Electric IOUs report that 1,876 customers owned solar photovoltaic systems in 2010, up from 1,044 in 2009. For all electric utilities, about 20,404 kilowatts (20.4 MW) of solar photovoltaic capacity from 2,833 systems have been installed statewide. Table 7 displays the information on customer-owned renewable generation for 2010 reported by Florida's utilities.

**Table 7. State of Florida: Customer Owned Renewable Generation**

| Utility Type | Connections | Non-Firm Capacity (MW) |
|---|---|---|
| Investor-Owned | 1,876 | 13.0 |
| Municipal | 494 | 4.1 |
| Rural Electric Cooperatives | 463 | 3.3 |
| **Total** | **2,833** | **20.4** |

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

## PLANNED RENEWABLES ADDITIONS

Florida's utilities plan to construct or purchase an additional 765.6 MW of renewable generation over the ten-year planning period. The expected major contributors to actual energy generation are planned biomass resources. Table 8 summarizes the overall proposed planned increases by generation type of all utilities.

**Table 8. State of Florida: Planned Renewable Resource Net Additions**

| Fuel Type | Capacity (MW) |
|---|---|
| Solar | 504.5 |
| Wind | 0.0 |
| Biomass | 308.0 |
| Municipal Solid Waste | 75.0 |
| Waste Heat | 0.0 |
| Landfill Gas | 18.1 |
| Hydro | 0.0 |
| **Total** | **905.6** |

Sources: FRCC 2011 Load & Resource Plan, Utilities' 2011 TYSPs

On the following pages, Table 9, Table 10, and Table 11 provide detailed lists of the renewable resources planned for construction in Florida over the ten-year planning horizon. Table 9 shows that, of the renewable firm capacity planned over the ten-year horizon, the majority is biomass and MSW that will be purchased by IOUs. As of January 2011, firm capacity contracts represent 49 percent of total planned renewable additions.

**Table 9. State of Florida: List of Planned Renewable Firm Capacity**

| Purchasing Utility | Facility Name | Fuel Type | Capacity (MW) | In-Service Date |
|---|---|---|---|---|
| **Investor-Owned Utilities** | | | | |
| FPL | Solid Waste Authority of Palm Beach | MSW | 40.0 | 2015 |
| PEF | BG&E #1 | WDS | 45.0 | 2012 |
| PEF | FB Energy | AB | 60.0 | 2014 |
| PEF | Trans World Energy | WDS | 40.0 | 2013 |
| | **Subtotal** | | **185.0** | |
| **Municipal Utilities** | | | | |
| GRU | Gainesville Renewable Energy Center | WDS | 100.0 | 2013 |
| JEA | Trailridge | LFG | 9.1 | 2011 |
| OUC | Holopaw | LFG | 5.3 | 2011 |
| OUC | Port Charlotte | LFG | 3.7 | 2012 |
| TAL | Renewable Fuels Tallahassee | MSW | 35.0 | 2013 |
| | **Subtotal** | | **153.1** | |
| **Cooperative Utilities** | | | | |
| SEC | Southeast Renewable Fuels | AB | 25.0 | 2012 |
| | **Sub-Total** | | **25.0** | |
| | **Total** | | **363.1** | |

Source: FRCC Load & Resource Plan, Utilities' 2011 TYSPs

Pursuant to current state and federal law, payments made by utilities to generation facilities utilizing renewable energy sources are capped at the utility's avoided cost for capacity and energy. Since last year's reporting, planned firm additions have decreased with the completion of facilities and the cancellation of several pending contracts. PEF reported that BG&E had cancelled a planned 75 MW woody biomass facility. Additionally, three facilities proposed by Hathaway totaling 48 MW have been withdrawn. However, several new additions were included in the ten-year planning period, such as PEF's contract with Trans World Energy for 40 MW and FPL's 40 MW uprate of the existing Solid Waste Authority facility. Municipal utilities GRU and TAL plan to contract renewable centers for combined purchases of 135 MW, while OUC is expecting to purchase power from two LFG facilities with a total output of 9 MW.

Table 10 shows that most of the non-firm capacity planned in Florida will be purchased by IOUs. These additions are almost exclusively solar powered. The largest planned addition in solar purchases will be through a series of as-available contracts between Progress Energy and a third-party solar producer, National Solar.

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

| Purchasing Utility | Facility Name | Fuel Type | Capacity (MW) | In-Service Date |
|---|---|---|---|---|
| **Investor-Owned Utilities** | | | | |
| PEF | Eliho | WDS | 8.0 | 2011 |
| PEF | E2E2 | WDS | 30.0 | 2012 |
| PEF | Blue Chip Energy #1 | SUN | 50.0 | 2010 |
| PEF | National Solar #5-10 | SUN | 400.0 | Varies |
| | **Subtotal** | | **488.0** | |
| **Municipal Utilities** | | | | |
| GRU | Solar FIT Program | SUN | 8.4 | Varies |
| LAK | Thermal Solar Facility | SUN | 15.0 | 2011-2016 |
| LAK | Unknown Solar Facility | SUN | 24.0 | 2011-2017 |
| OUC | Regenesis Stanton Energy Center | SUN | 5.9 | 2012 |
| OUC | CNL/City Hall | SUN | 0.5 | 2012 |
| OUC | GSLD Solar | SUN | 0.7 | 2012 |
| | **Subtotal** | | **54.5** | |
| | **Total** | | **542.5** | |

Source: FRCC Load & Resource Plan, Utilities' 2011 TYSPs

National Solar plans to construct five individual stand-alone solar facilities with targeted in-service dates of mid-2013, and PEF will purchase the entire output from National Solar. As of the date of the contract filings, the combined facilities' generation will contribute 400 MW of non-firm power.

In the 2011 TYSPs, utilities reported very little utility-owned renewable facility additions. Table 11 shows that the remaining planned additions consist of small solar projects that generate less than 100 kilowatts of non-firm capacity.

### Table 11. List of Planned Utility-Owned Renewable Additions[16]

| Purchasing Utility | Facility Name | Fuel Type | Capacity (MW) | In-Service Date |
|---|---|---|---|---|
| **Municipal Utilities** | | | | |
| OUC | Harmony | SUN | 0.005 | 2013 |
| TAL | Jake Gaither Golf | SUN | 0.015 | 2011 |
| TAL | StarMetro | SUN | 0.010 | 2011 |
| GRU | Administration Building Atrium | SUN | 0.001 | 2011 |
| | **Subtotal** | | **0.020** | |
| | **Total** | | **0.020** | |

Source: FRCC Load & Resource Plan, Utilities' 2011 TYSPs

[16] Data provided from the 2011 Ten-Year Site Plans and FRCC's 2011 Regional Load and Resource Plan.

In the previous plan year, FPL announced its intention to expand its existing DeSoto Solar Facility in two phases with an additional 49 MW by 2011 and 226 MW by 2013. However, as of the date of this report, FPL has withdrawn their Site Certification Application for the proposed project and did not include any expansion plans for the DeSoto facility in its 2011 TYSP report.

## UPDATED NAVIGANT CONSULTING REPORT

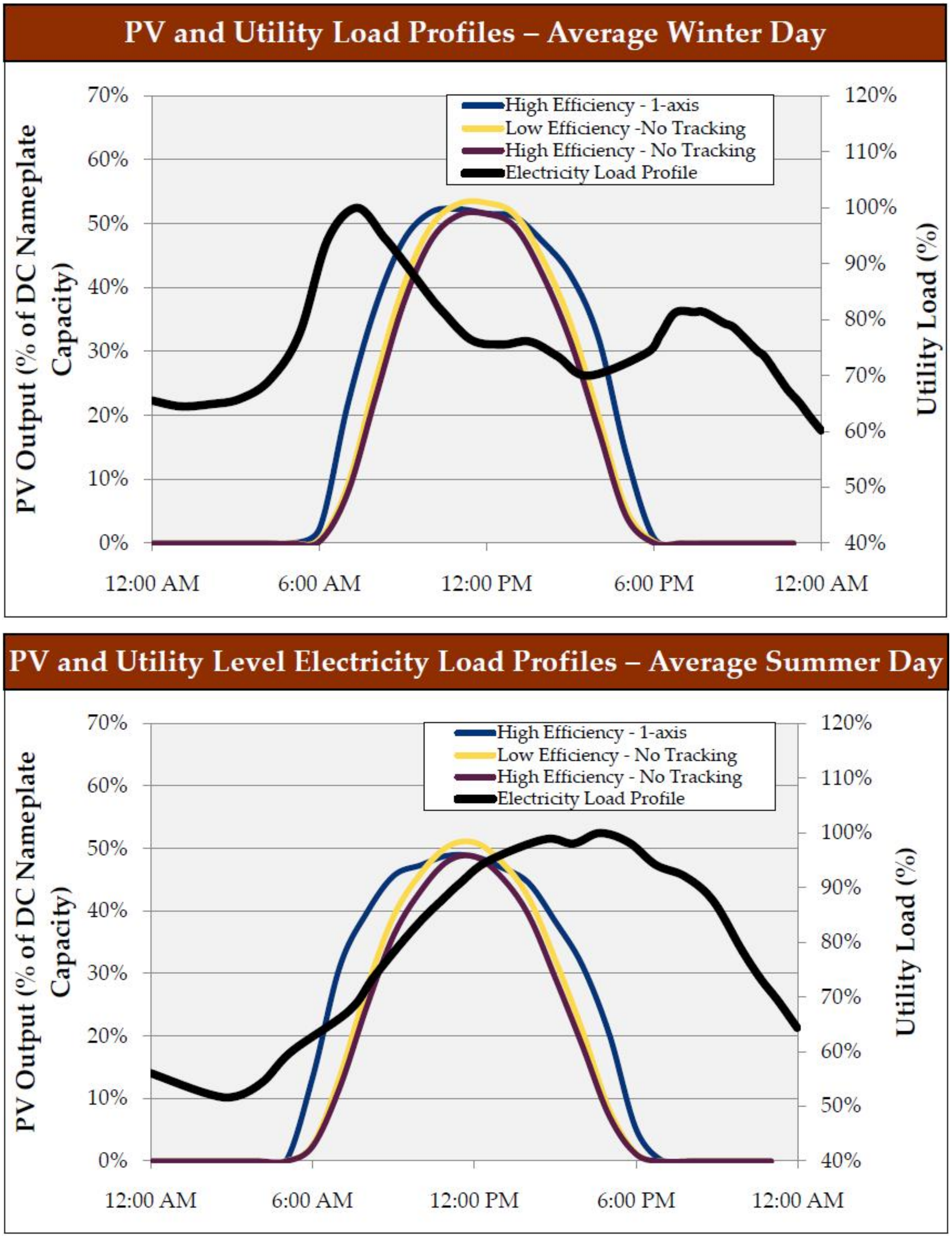
The Commission contracted with Navigant Consulting in early 2010 to update its 2008 analysis with current conditions. In June 2010, Navigant Consulting released new comparisons of cost estimates for different renewable generating facilities. Navigant Consulting also provided additional detail pertaining to Florida's renewable resource which it identified as having the most technical potential for growth, solar photovoltaic facilities. Findings from the report are summarized below.

In the 2010 Navigant Consulting Report Update, the most meaningful findings include changes in prices of renewable technologies. PV module prices have fallen and commodity costs for PV units have decreased during the recession, but both are returning to near their pre-recession levels. Wind power prices have also decreased due to the recession, while utility turbine prices have risen as worldwide demand catches up with supply. According to the 2010 Navigant Consulting Report Update, no large performance breakthroughs occurred for any technology. Because Navigant Consulting found solar resources to hold the most potential in Florida, the remainder of the 2010 Navigant Consulting Report Update focuses on solar power.

The 2010 Navigant Consulting Report Update estimates that solar power systems have increased in efficiency while overall prices have decreased up to 40 percent since 2008. In spite of these changes, solar power systems continue to have some of the highest capital costs per kW of any renewable generating system. Varying the methods of using solar energy involving solar tracking technology and alternating solar film receptors produces a slight range of energy output and net capacity factors. In addition, the ability of solar PV systems to provide energy are limited to daytime hours. Supplemental battery storage units may alleviate this issue, but the costs of batteries are not included in Navigant Consulting's estimates.

Even with these advancements, capacity factors of solar panels are projected to remain below 25 percent. Such results indicate that solar PV facilities operate more like a conventional peaking unit and will not replace the need for base-load generating facilities. However, Navigant Consulting also reported that operating characteristics for these systems do not correlate with daily peak load hours. As shown in Figure 10, Navigant Consulting estimates that the peak output from solar PV facilities reaches a maximum of approximately 50 percent of the rated capacity, and occurs after the system's winter peak hour and before the system's summer peak hour. As a result, a solar PV facility's ability to provide reliability benefits appears limited.

**Figure 10. Solar PV Output and Utility Seasonal Load Profiles**



## TRADITIONAL GENERATION

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, and renewable generation, the need for traditional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity and the per capita consumption continue 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, pipeline considerations, and fluctuating costs are considerations for selection of natural gas generators, while water supply and consumption, land area limitations, access to delivery options, environmental concerns, and cost of emission controls are factors for selection of coal units. High construction costs, very long lead times, uncertainty over spent fuel disposal, and most recently the crisis at the Fukushima nuclear plant in Japan are considerations for selection of nuclear generation.

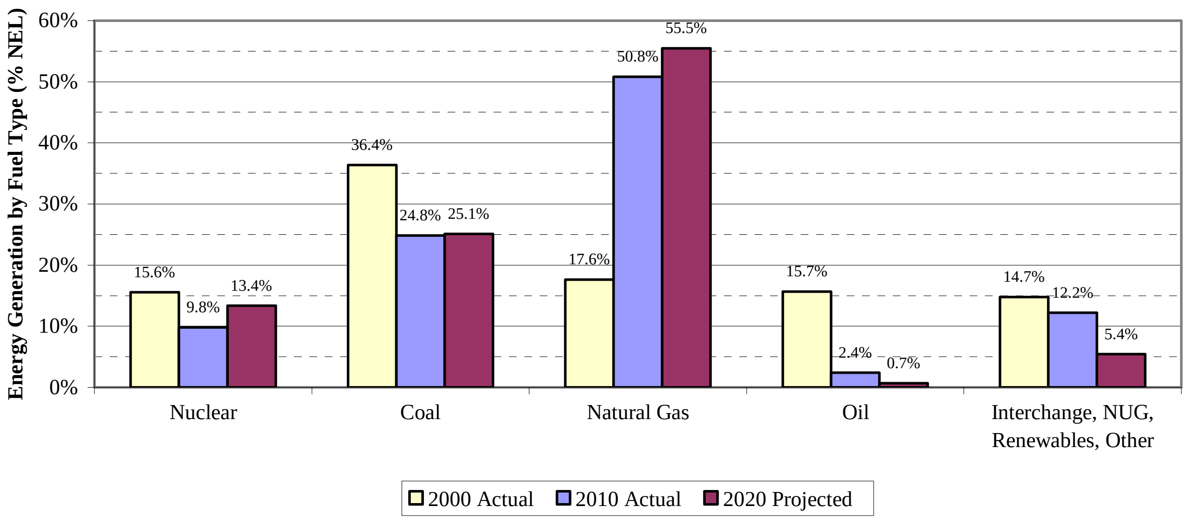
Gas fired units have almost exclusively been selected in recent years due to higher thermal efficiencies, lower capital costs, shorter periods for permitting and construction, and sometimes the smaller land areas required. In past years, a key factor in choosing between natural gas and coal was the number of years required for a coal unit to become cost effective. Higher up-front construction costs result in higher customer risk associated with uncertainty over fuel cost differential. As the price difference between natural gas and coal widened, the break-even period decreased. In other words, as gas prices rose faster than coal prices, the number of years required for fuel savings to outweigh coal's higher construction costs decreased.

In the last ten years, almost 97 percent of all capacity additions to Florida's electric system use natural gas as the primary fuel. Coal units that were planned have been cancelled, and nuclear units that have been approved have been delayed beyond the planning horizon. Currently, other than approximately 900 MW of renewable generation, all of the additional generation planned for the next ten years will use natural gas as a fuel source.

### FUEL DIVERSITY

The continued addition of natural gas-fired generating units has once again produced an electric system in Florida that is heavily dependent on a single fuel source. As Figure 11 shows, more than 50 percent of the electric energy in Florida is natural gas-fired.

**Figure 11. State of Florida: Energy Generation by Fuel Type (Percent of Total)**



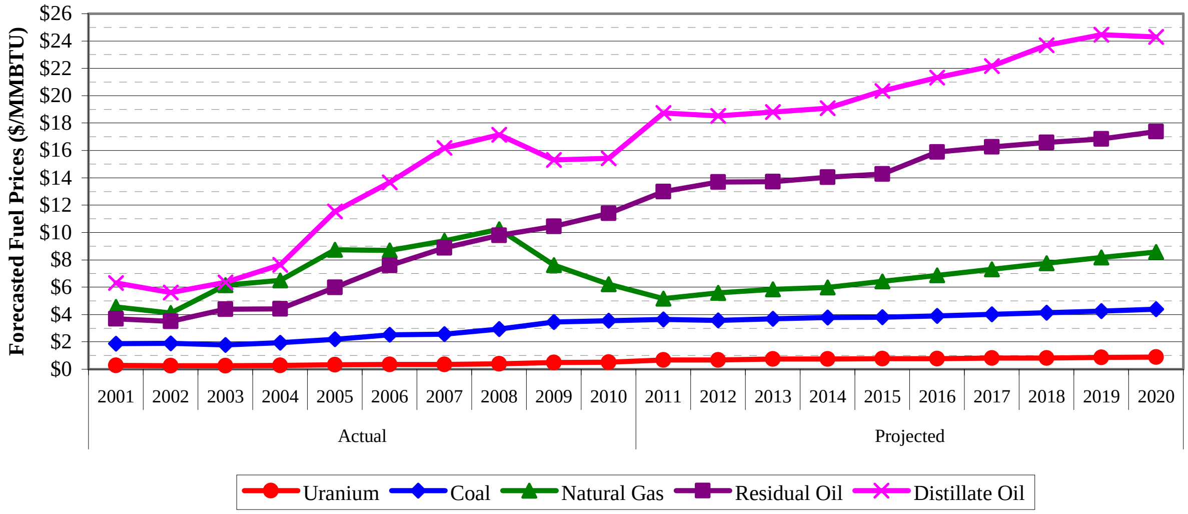

Source: FRCC's 2001 and 2011 Load & Resource Plans

## 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. However, this situation does not necessarily hold true presently.

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. However, as Figure 12 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 level throughout the planning horizon.

**Figure 12. Reporting Utilities: 2010 Weighted Average Fuel Price Forecast**




Source: Response to FPSC Data Request

Previous Ten-Year Site Plan reviews indicated that increases in gas prices may bring an end to the almost exclusive addition of natural gas-fired generation. As can be seen from Figure 12, the expectation of high prices for natural gas has not materialized and although it is forecasted to increase steadily, the rate of increase is more moderate than was previously contemplated.

Utility plans for a balanced fuel system have historically been highly dependent on 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 severely 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.

## SUMMARY OF RESOURCE ADDITIONS

The Florida Public Service Commission is given exclusive jurisdiction by the Legislature, through the Power Plant Siting Act, 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. The Commission has granted determinations of need for several generating units of various technology types in recent years, although virtually all of the units actually constructed have been natural gas-fired.

The following tables are a representation of all changes to generation systems that appear in the 2011 TYSPs for the reporting utilities. Table 12 shows all additional generating units as well as all unit retirements, uprates, and decreased purchases.

**Table 12. State of Florida: Proposed Capacity Changes As Reported**

| Fuel Type | Unit Type | Summer Capacity Changes (MW) | |
|---|---|---|---|
| | | 2010 Forecast (2010-2019) | 2011 Forecast (2011-2020) |
| **Natural Gas** | Combined Cycle | 5,232 | 7,846 |
| | Combustion Turbine | 623 | 1,379 |
| | Steam | -276 | -147 |
| **Coal** | Steam | -45 | 23 |
| | Integrated Coal Gasification | -15 | 0 |
| **Oil** | Combustion Turbine & Diesel | -68 | 0 |
| | Steam | -2,444 | -696 |
| **Nuclear (NUC)** | Steam | 1,658 | 631 |
| **Firm Purchases** | Independent Power Producer (IPP) | -482 | -512 |
| | Interchange | -746 | -754 |
| | Non-Utility Generator (NUG) | -234 | -137 |
| | Renewables | 0 | 0 |
| **NET CAPACITY ADDITIONS** | | **3,203** | **7,632** |

Source: FRCC's 2010 and 2011 Load & Resource Plans

Table 13 contains all the planned additional combustion turbine units listed. Because these units do not utilize steam, they are not required to obtain PPSA certification or a determination of need by the Commission.

**Table 13. State of Florida: Combustion Turbine Generation Additions**

| Utility | Generating Unit Name | Summer Capacity (MW) | In-Service Date |
|---|---|---|---|
| OUC | Stanton Energy Center | 185 | 4 / 2017 |
| PEF | Unknown | 178 | 6 / 2018 |
| TECO | Future CT 1 | 56 | 5 / 2013 |
| TECO | Future CT 2 | 56 | 5 / 2013 |
| TECO | Future CT 3 | 56 | 5 / 2013 |
| TECO | Future CT 4 | 56 | 5 / 2014 |
| TECO | Future CT 5 | 56 | 5 / 2015 |
| TECO | Future CT 6 | 56 | 5 / 2016 |
| TECO | Future CT 7 | 56 | 5 / 2017 |
| TECO | Future CT 8 | 56 | 5 / 2018 |
| TAL | Hopkins CT 5 | 46 | 5 / 2020 |
| SEC | Unnamed CT1 | 158 | 12 / 2018 |
| SEC | Unnamed CT2 | 158 | 5 / 2019 |
| SEC | Unnamed CT3 | 158 | 5 / 2019 |
| SEC | Unnamed CT4 | 158 | 12 / 2020 |
| SEC | Unnamed CT5 | 158 | 12 / 2020 |
| SEC | Unnamed CT6 | 158 | 12 / 2020 |

Source: Responses to FPSC Data Request

Table 14 displays the new combined cycle generating units planned by the reporting utilities. These units do require PPSA certification and a determination of need. Dashes instead of dates denote units which have not yet obtained a need approval or PPSA certification.

**Table 14. State of Florida: Combined Cycle Generation Additions**

| Utility | Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|---|
| | | | Need Approved (Commission) | PPSA Certified | |
| FPL | West County Energy Center 3 | 1219 | Sep-08 | Nov-08 | Jun-11 |
| FPL | Cape Canaveral NGCEC | 1210 | Sep-08 | Aug-09 | Jun-13 |
| FPL | Riviera NGCEC | 1212 | Sep-08 | Nov-09 | Jun-14 |
| FPL | Port Everglades Modernization | 1277 | --- | --- | Jun-16 |
| FPL | Greenfield CC Unit #2 | 1191 | --- | --- | Jun-20 |
| TECO | Polk 2-5 CC 1 | 970 | --- | --- | May-19 |
| FMPA | Cane Island Unit 4 | 300 | Aug-08 | Dec-08 | May-11 |
| SEC | Unnamed CC1 | 196 | --- | --- | Dec-20 |
| SEC | Unnamed CC2 | 196 | --- | --- | Dec-20 |
| PEF | Unsited CC | 767 | --- | --- | Nov-20 |

Source: Responses to FPSC Data Request

Table 15 shows the planned uprates to the nuclear units for FPL and PEF. Because the return to service of PEF's Crystal River Unit 3 has been delayed until 2014, the uprate project will almost certainly be delayed past the listed date of May, 2013.

**Table 15. State of Florida: Nuclear Generation Uprates**

| Primary Utility Owner* | Uprated Generating Unit Name | Added Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|---|
| | | | Need Approved (Commission) | PPSA Certified | |
| FPL | St. Lucie 1 | 122 | Jan-08 | Sep-08 | 3/2012 |
| FPL | Turkey Point 3 | 109 | Jan-08 | Oct-08 | 6/2012 |
| FPL | St. Lucie 2 * | 110 | Jan-08 | Sep-08 | 10/2012 |
| FPL | Turkey Point 4 | 109 | Jan-08 | Oct-08 | 2/2013 |
| PEF | Crystal River 3 | 154 | Feb-07 | Aug-08 | 11/2014 |

* Several of Florida's nuclear units are jointly owned. For simplicity, the majority owner is listed here.
Source: Responses to FPSC Data Request

# INDIVIDUAL UTILITIES

## *INVESTOR OWNED UTILITIES*

- **Florida Power & Light**
- **Progress Energy Florida**
- **Tampa Electric Company**
- **Gulf Power Company**

# *FLORIDA POWER & LIGHT (FPL)*

Florida Power & Light (FPL) is the state's largest investor-owned utility, with a service area of approximately 27,650 square miles in South Florida and along the eastern coast of Florida. FPL had an average of more than 4,520,000 customers in 2010. FPL's electric system consists of 87 generating units at sixteen sites in Florida, with a total summer system generation of 23,722 MW. In addition, FPL has partial ownership of three coal facilities located outside its service territory, two in Jacksonville and one in Georgia. FPL is a vertically integrated utility with more than 6,700 circuit miles of transmission lines and 586 substations included in its system.

In 2010, FPL's total net energy for load (NEL) was 114,373 GWh. This figure is approximately 46 percent of the NEL generated in the entire state for that year.

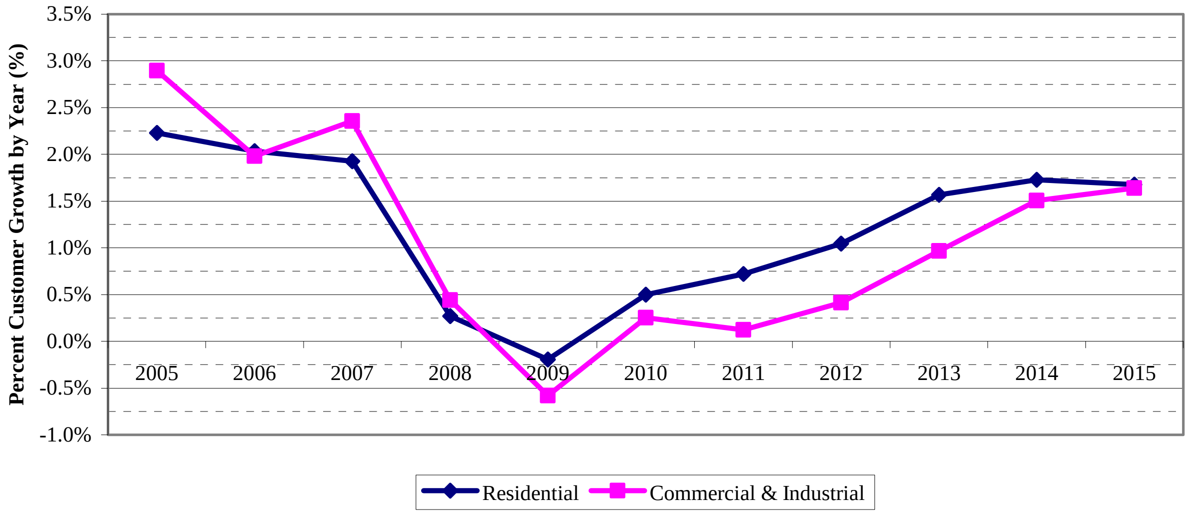
**Peak Demand and Energy Forecasts**

FPL develops forecasts for energy and peak loads which are based on economic conditions and weather data. Projections for the national and Florida economy, population growth, and weather variables are all important factors in the development of forecasts for energy sales and peak demand.

The economic conditions in the current plan year are similar to those of the previous year, but signs that a recovery is underway are beginning to emerge. Population growth has begun to improve, but FPL does not expect its growth in customers to reach the level historically experienced until 2014-2015.

Figure 13 is a graphical representation of the negative customer growth experienced by FPL over the past five years, and the slow return to positive growth it expects for the next five years. The data for 2005 through 2010 are actual, and 2011 through 2015 are projected.

**Figure 13. FPL: Customer Growth Rates**

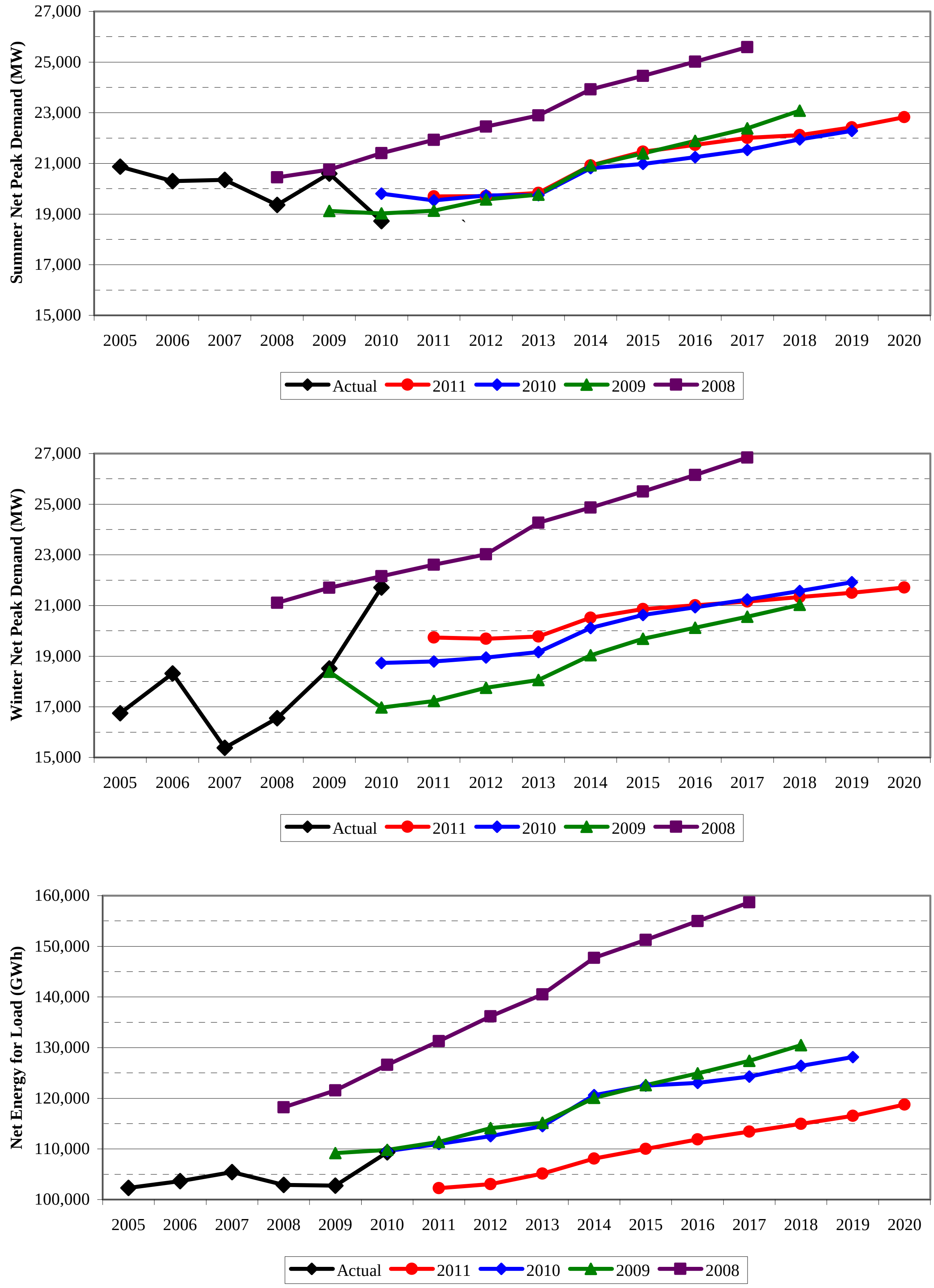



Source: FPL 2011 TYSP

The following three graphs in Figure 14 show FPL's actual peak demand for both the summer and winter seasons, and NEL for the years since 2005. The forecasted values are also shown through the current planning horizon. These figures clearly show that the current forecasts for summer and winter peak demand are very similar to the 2010 levels, only somewhat flatter. However, the current NEL forecast has been adjusted downwards by approximately 10,000 GWh. The actual value for winter peak demand in 2010 is higher than was expected, due to an unusually cold winter season.

Analysis of FPL's historical forecast accuracy for total retail energy sales from 2006 through 2010 shows that FPL's average forecast error is 4.24 percent. This value indicates that FPL tends to over-forecast its retail energy sales by 4.24 percent, which is almost twice the average forecast error for all eleven of the Ten-Year Site Plan utilities. When all the reporting utilities' average error rates are combined, the resulting composite average error rate is 2.44 percent.

**Figure 14. FPL: Demand & Energy Forecasts**



**Demand-Side Management**

The DSM goals for FPL set in 2009 were higher than the goals previously set in the 2004 goal-setting proceeding. FPL's 2011 Ten-Year Site Plan includes the 2009 goals in its calculations for reserve margin. However, due to concern that implementing the DSM Plan filed by FPL in 2010 would result in an undue rate impact on customers, the Commission modified FPL's DSM Plan such that it would consist of those programs that were already in place.[17] The overall result of this decision is that the savings in demand and energy resulting from the approved DSM Plan will be somewhat smaller what is reflected in FPL's 2011 TYSP.

**Reliability Criteria**

As mentioned in the Statewide Perspective section of this review, FPL maintains a minimum 20 percent reserve on its system. Figure 15 displays the projected reserve margin for FPL through the planning horizon for both the summer and winter peak periods. The figure shows that FPL is projecting to meet or exceed its minimum reserve margin throughout the ten-year planning period.

The reserve shown in Figure 15 is inclusive of the values for DSM that were established in 2009. Since the actual savings from DSM will most likely be lower than what was projected in FPL's 2011 Ten-Year Site Plan, the reserve could be somewhat lower than what is shown in Figure 15.

In its 2011 Plan, FPL expresses concern regarding the increasing dependence on DSM in its planning reserve. This situation is of concern because DSM, load control, and interruptible load programs are strictly voluntary, involving only customers that choose to participate in them. These customers can and do opt out of such programs, especially following a period wherein the utility has exercised interruption of service more often than usual. As shown in Figure 16, when taking only supply-side resources into consideration, the level of reserve for the summer peak season drops to between approximately 10 and 15 percent. For this reason, FPL has indicated that it is studying the possibility of instituting a generation-only minimum reserve.

[17] Order No. PSC-11-0346-PAA-EG in Docket No. 100155-EG, issued August 16, 2011.

**Figure 15. FPL: Reserve Margin Projections**

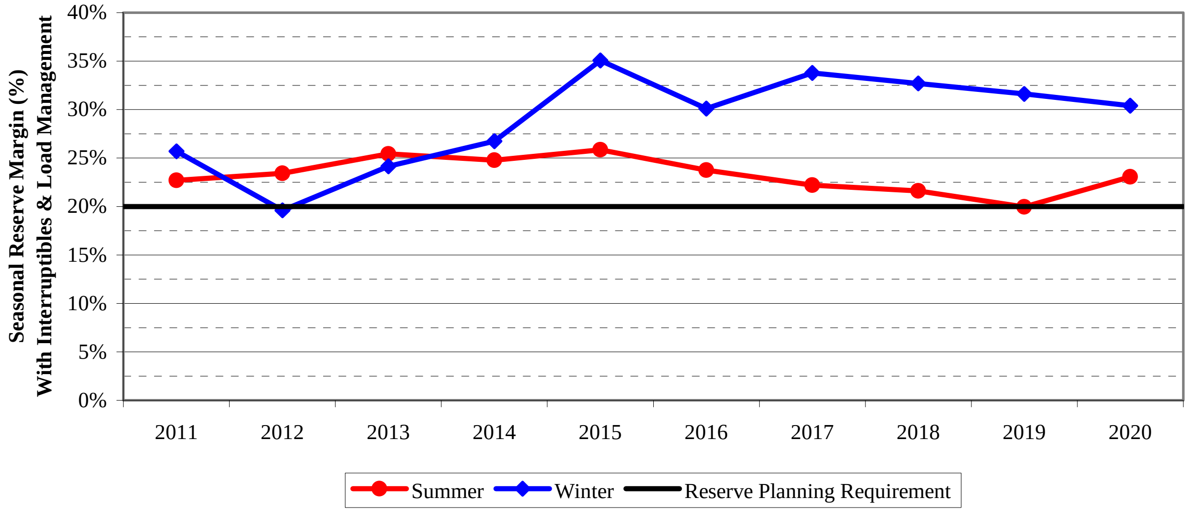
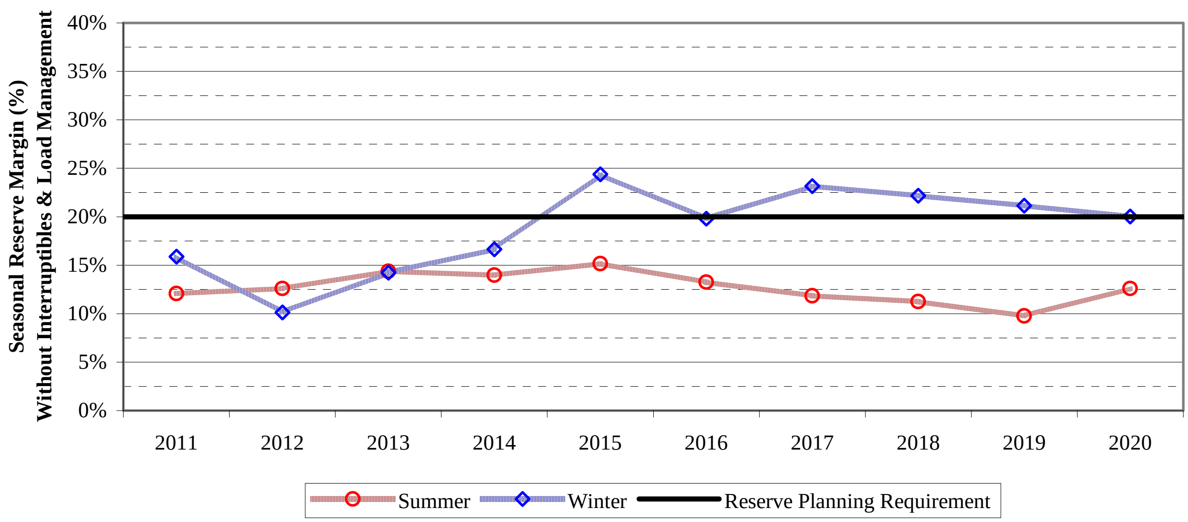



**Figure 16. FPL: Generation-Only Reserve Margin Projections**

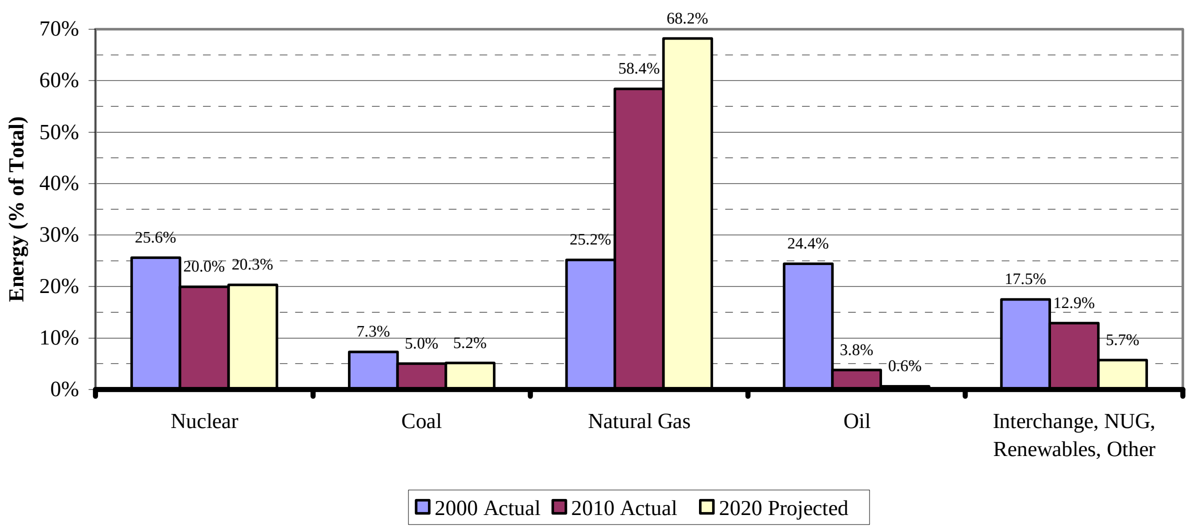



FPL's 2011 Ten-Year Site Plan reports that it would need to begin scheduling planned maintenance of its generating units during peak demand periods, thereby reducing the available capacity at those critical times. However, FPL later informed the Commission that it has determined that under current operating parameters the required maintenance may be performed during the non-peak periods. This change lowers FPL's projected resource needs in all future years by 350 MW of capacity, and the net effect of this change is to increase the reserve margin by approximately 1.8 percent.

## Fuel Diversity

Figure 17 clearly shows the importance of natural gas in FPL's system. In 2010, more than 58 percent of the energy generated by FPL was produced from natural gas-fired units. This share of energy generated is projected to increase to more than 68 percent by the end of the planning horizon.

**Figure 17. FPL: Energy Generation by Fuel Type (Percent of Total)**




Source: FPL 2001 and 2011 TYSPs

## Generation Additions

FPL's 2011 TYSP includes two new combined cycle generation units that did not appear in the 2010 Plan. The 2011 Plan indicates that these two new units are to come into service in 2016 and 2020, and that the sites could be greenfield, brownfield, or modernizations of existing units.

Since submitting its 2011 Plan, FPL has notified the Commission that the new greenfield unit scheduled to be in-service in 2016 will in fact be a modernization of an existing generation facility. FPL filed a petition for an exemption to the bid rule for the modernization of its Port Everglades plant, which currently consists of four 1960's era oil and natural gas-fired steam electric generating units totaling 1,200 MW of generating capacity, and replacing them with a highly efficient, state-of-the-art combined cycle power plant with up to 1,280 MW of generation. All of the new generation units that FPL is planning to add to its system are shown in Table 16.

## Table 16. FPL: Generation Additions by Technology Type

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Nuclear Unit Additions (uprates)** | | | | |
| St. Lucie 1 Extended Power Uprate | 122 | Jan-08 | Sep-08 | 3/2012 |
| Turkey Point 3 Extended Power Uprate | 109 | Jan-08 | Oct-08 | 6/2012 |
| St. Lucie 2 Extended Power Uprate | 110 | Jan-08 | Sep-08 | 10/2012 |
| Turkey Point 4 Extended Power Uprate | 109 | Jan-08 | Oct-08 | 2/2013 |
| **Combined Cycle Unit Additions** | | | | |
| West County Energy Center 3 | 1219 | Sep-08 | Nov-08 | 6/1/2011 |
| Cape Canaveral NGCEC | 1210 | Sep-08 | Aug-09 | 6/1/2013 |
| Riviera NGCEC | 1212 | Sep-08 | Nov-09 | 6/1/2014 |
| Port Everglades Modernization | 1277 | None yet | None yet | 6/1/2016 |
| Greenfield CC Unit #2 | 1191 | None yet | None yet | 6/1/2020 |

Source: Responses to FPSC Data Requests

## *PROGRESS ENERGY FLORIDA (PEF)*

Progress Energy Florida (PEF) is Florida's second largest investor-owned utility, with a service area of approximately 20,000 square miles in central and west central Florida, including the cities of St. Petersburg and Clearwater, and the areas surrounding Orlando. PEF had approximately 1,613,000 customers in 2010. PEF's system included 63 generating units, and has a total summer system capacity of approximately 9,950 MW installed, and almost 1,800 MW of firm purchased capacity. PEF's system also includes approximately 5,000 circuit miles of transmission lines.

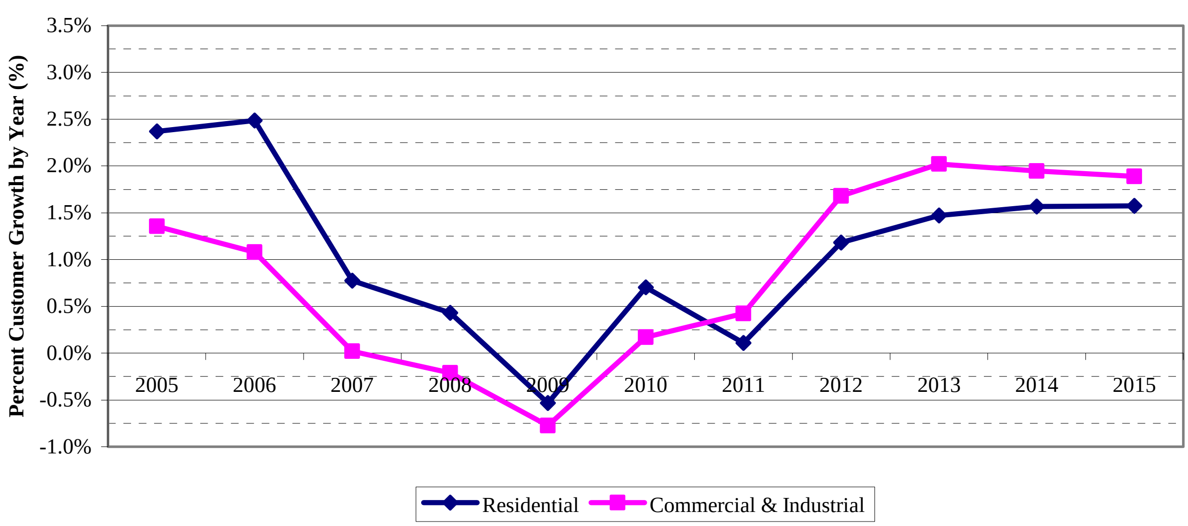
In 2010, PEF generated 46,160 GWh, which represents approximately 19 percent of the NEL in the entire state for that year.

### Peak Demand and Energy Forecasts

PEF develops economic, demographic, and weather-related assumptions upon which its forecasts are based. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon.

Figure 18 shows that, like most other electric utilities in Florida, PEF experienced negative growth in customers during the 2008-2010 period. However, PEF expects improved customer growth going forward due to improved economic conditions. PEF expects a growth rate in customers of 1.5 percent for the planning horizon, which is slightly higher than the previous ten-year average.

**Figure 18. PEF: Customer Growth Rates**



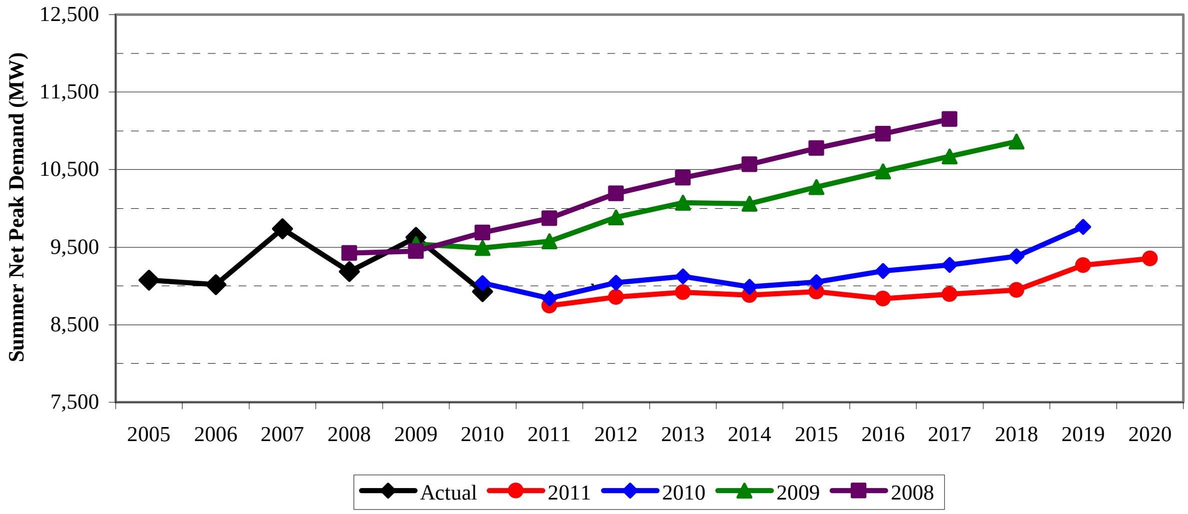

Source: PEF 2011 TYSP

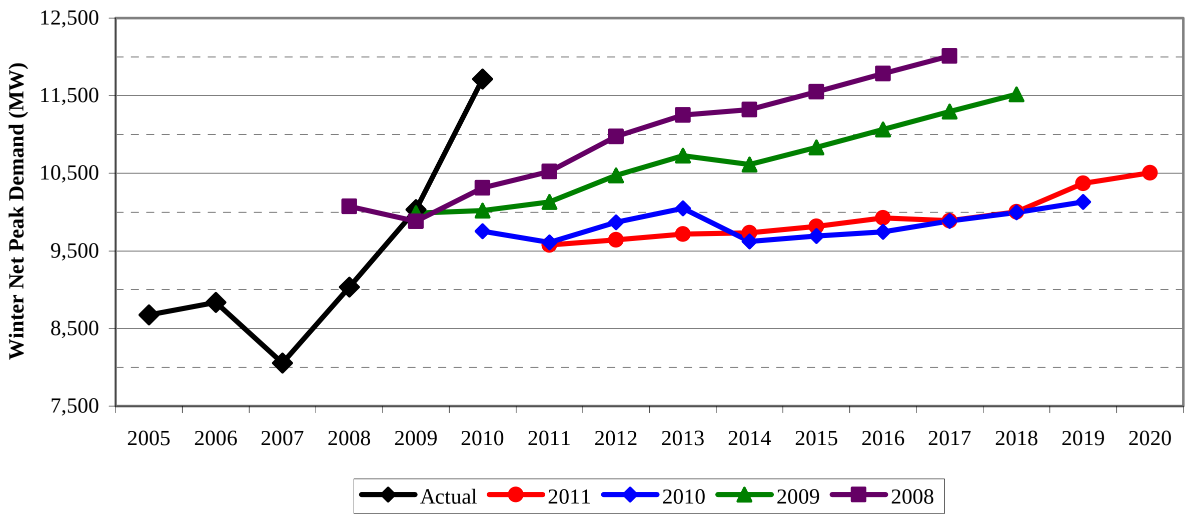
The expected growth rates for NEL and summer net firm demand are 1.6 percent and 0.8 percent, respectively. These growth rates are slightly lower than the rate of growth experienced in the previous ten-year period. Factors influencing these rates are a return to a normal weather summer peak, and negative wholesale summer peak growth from the 2010 MW level.

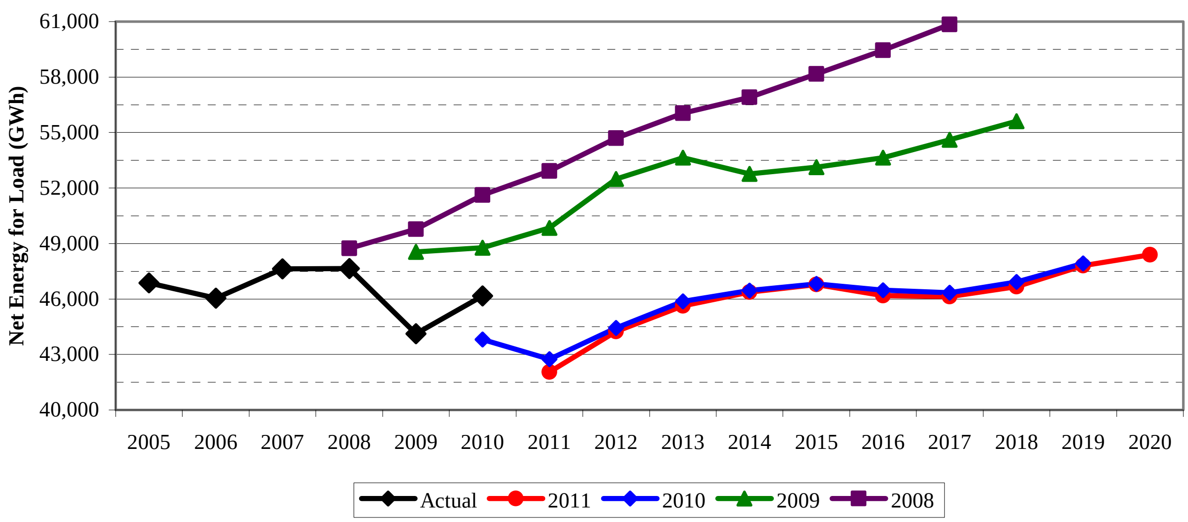
The following three graphs in Figure 19 illustrate PEF's relatively unchanged forecasts for summer demand, winter demand, and NEL for the current planning horizon. The actual value for winter peak demand in 2010 is higher than was forecasted because the winter season was unusually cold.

Analysis of PEF's historical forecast accuracy for total retail energy sales from 2006 through 2010 shows that PEF's average forecast error is 1.73 percent. This value indicates that PEF tends to over-forecast its retail energy sales by 1.73 percent. When compared with the overall average error rate of all reporting utilities, which is 2.44 percent, PEF's average error rate is lower. This result shows that PEF's forecasting is more accurate than the statewide average.

**Figure 19. PEF: Demand & Energy Forecasts**



## Demand-Side Management

The DSM goals for PEF set in 2009 were higher than the goals set in the 2004 goal-setting proceeding. PEF's 2011 Ten-Year Site Plan includes the 2009 goals in its calculations for reserve margin. However, due to concern that the DSM Plan filed by PEF in 2010 would have an undue impact on the costs passed on to consumers, the Commission modified PEF's 2010 DSM Plan such that it would consist of those programs that were already in place.[18] The overall result of this decision is that the savings in demand and energy will be somewhat smaller than the DSM savings reflected in PEF's 2011 TYSP.

## Reliability Criteria

PEF also maintains a 20 percent reserve margin, pursuant to a 1999 stipulation. Figure 20 displays the forecasted reserve margin for PEF throughout the planning horizon for both summer and winter peak periods. This figure shows that PEF's level of reserve is well above the minimum for most years, and only approaches the 20 percent minimum in the last year.

The high level of reserve shown in Figure 20 is indicative of the aggressive DSM goals on which PEF's 2011 Plan was based. Since the actual demand and energy savings from DSM will likely be lower, the actual reserve margin could be somewhat lower than what is shown in Figure 20.

Figure 21 is a graphical representation of the "generation-only" portion of PEF's reserve margin, which is the resulting level of reserve after contributions from load management and interruptible programs are removed from the calculation. This non-firm load can be considered as reserve capacity because, when the system load increases such that all generation reserve is committed, the utility can reassign system resources away from customers on load management and interruptible programs in order to serve its firm load. However, maintaining sufficient levels of generation reserve is important because implementing these types of programs on a regular basis can lead to customers opting out of such programs.

Both Figure 20 and Figure 21 display the PEF reserve margins modified from the values presented in PEF's 2011 TYSP. PEF states in its 2011 Plan that its nuclear generating unit, Crystal River Unit 3 (CR3), would become operational in 2011. However, since that time PEF has announced that it now expects that CR3 will not be back in-service until 2014. Therefore, any generation from CR3 in the years 2011-2014 was removed from the data used to develop the following two figures in order to provide a more accurate picture of PEF's reserve margin in those years.

[18] Order No. PSC-11-0347-PAA-EG in Docket No. 100160-EG, issued August 16, 2011.

**Figure 20. PEF: Reserve Margin Projections**

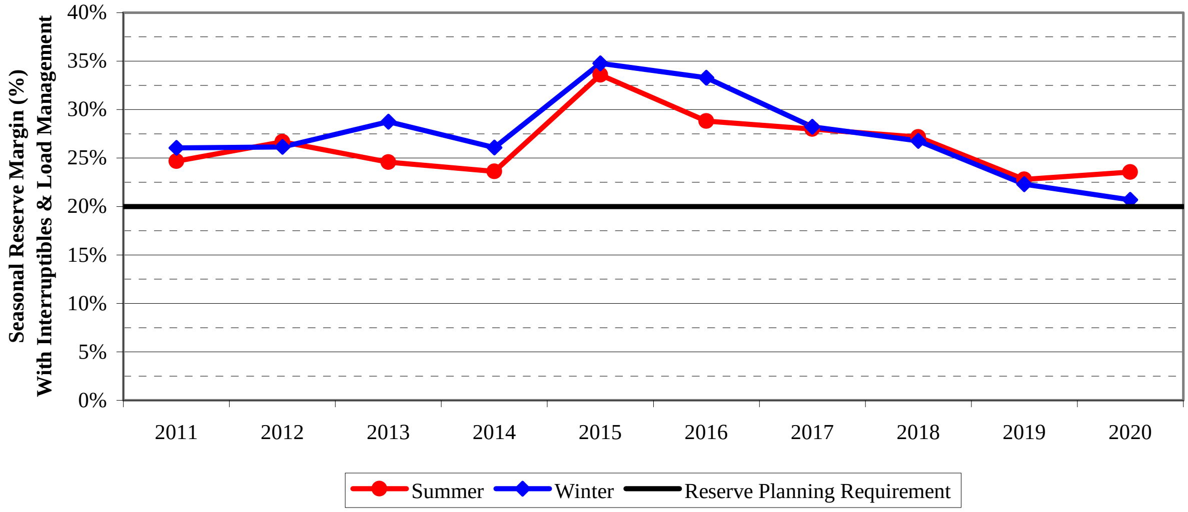
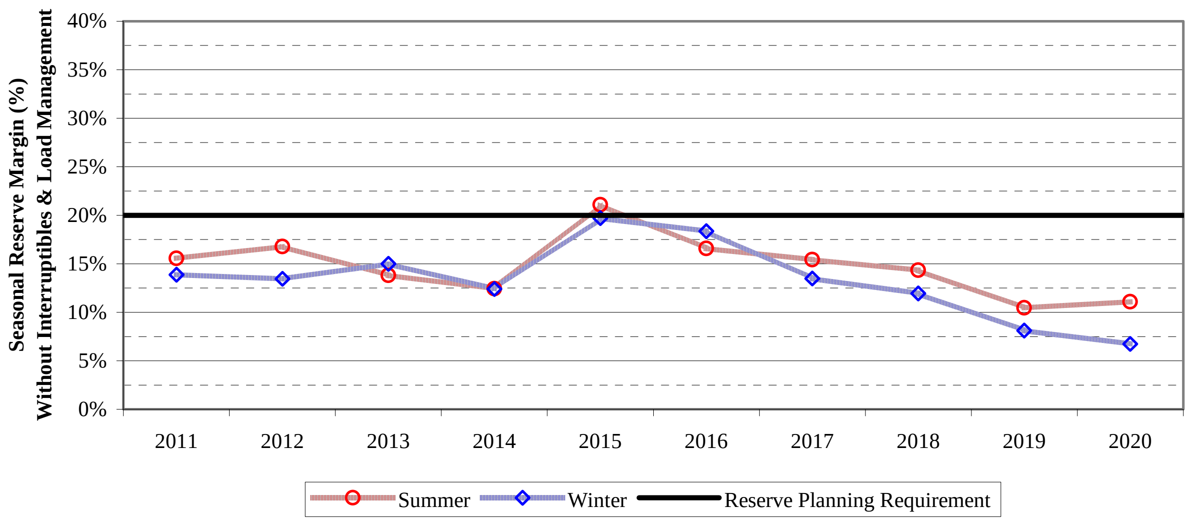



**Figure 21. PEF: Generation-Only Reserve Margin Projections**

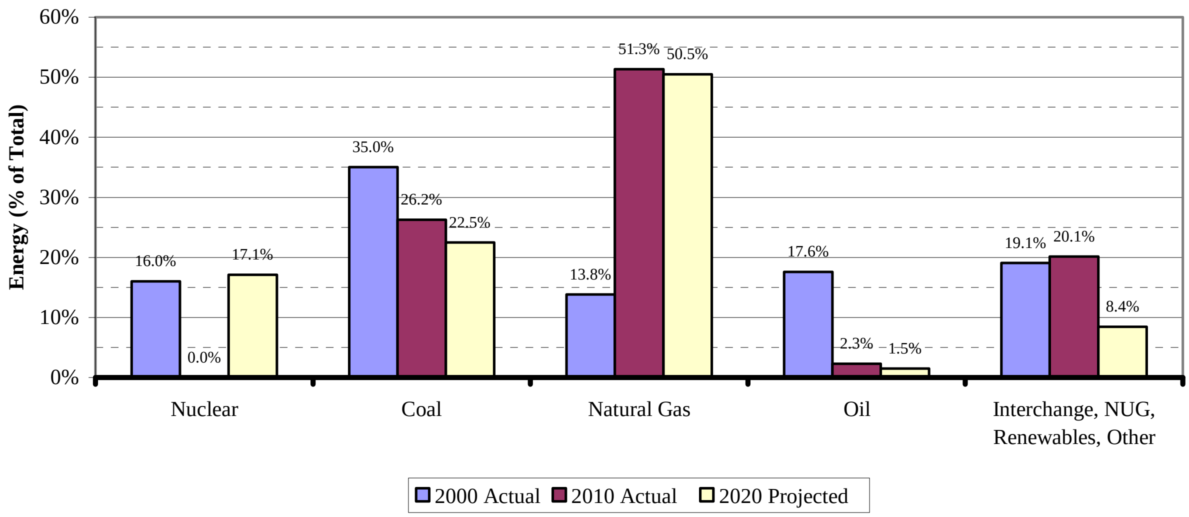



Source: PEF 2011 TYSP, Responses to FPSC Data Requests

## Fuel Diversity

Unlike FPL, Figure 22 shows that PEF's system composition is not projected to change substantially throughout the ten-year planning horizon.

**Figure 22. PEF: Energy Generation by Fuel Type (Percent of Total)**




Source: PEF 2001 and 2011 TYSPs

The fact that PEF's nuclear unit, CR3, has been out of service since October 2009 has affected PEF's unit utilization. Nuclear generation represents 8 percent of PEF's capacity, but no energy was generated from CR3 in 2010. However, PEF expects that more than 17 percent of the energy generated in 2020 will come from nuclear. Presently, the two new nuclear generating units at Levy, for which the Commission approved the need in 2008, are projected to be in-service in 2021 and 2022. Because these years are outside of the current planning horizon, these two units do not appear in PEF's TYSP.

## Generation Additions

Table 17 shows the new generation included in PEF's 2011 TYSP and responses to subsequent data requests. The in-service date for the uprate of CR3 has been delayed due to the extended outage of that nuclear unit. The additional CC unit does not appear in PEF's 2011 TYSP as filed, but was added in a later data request.

### Table 17. PEF: Generation Additions by Technology Type

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Nuclear Unit Additions (uprates)** | | | | |
| Crystal River 3 | 154 | Feb-07 | Aug-08 | 11/2014 |
| **Combustion Turbine Unit Additions** | | | | |
| Unsited CT | 178 | n/a | n/a | 6/2018 |
| **Combined Cycle Unit Additions** | | | | |
| Unsited CC | 767 | None Yet | None Yet | 11/2020 |

Source: Responses to FPSC Data Request

## *TAMPA ELECTRIC COMPANY (TECO)*

Tampa Electric Company (TECO) is an investor-owned utility with more than 660,000 customers, and a fleet of generating units including fossil steam, combined cycle, combustion turbine, and an integrated coal gasification combined cycle unit.

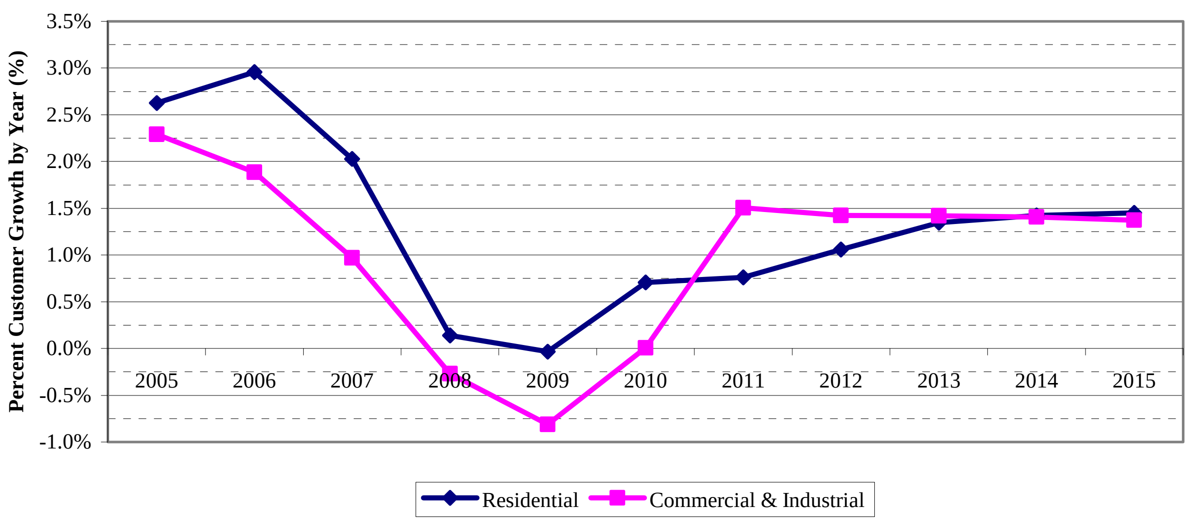
TECO's total NEL for 2010 was 19,213 GWh, which represents approximately 8.4 percent of the NEL generated statewide that year.

**Peak Demand and Energy Forecasts**

TECO's customer, demand, and energy forecasts are the foundation from which the projection with the highest probability of occurrence is developed.

Figure 23 shows the growth rates in both residential and commercial/industrial classes for actual from 2005 to 2010, and projected growth from 2011 to 2015. Similar to other utilities, TECO experienced a drop in customer accounts beginning in 2005, but also like other utilities, a slow return to positive growth over the next few years for residential customers is expected. The projected growth for commercial and industrial classes is expected to be very slightly negative after 2011.

**Figure 23. TECO: Customer Growth Rates**




Source: TECO 2011 TYSP

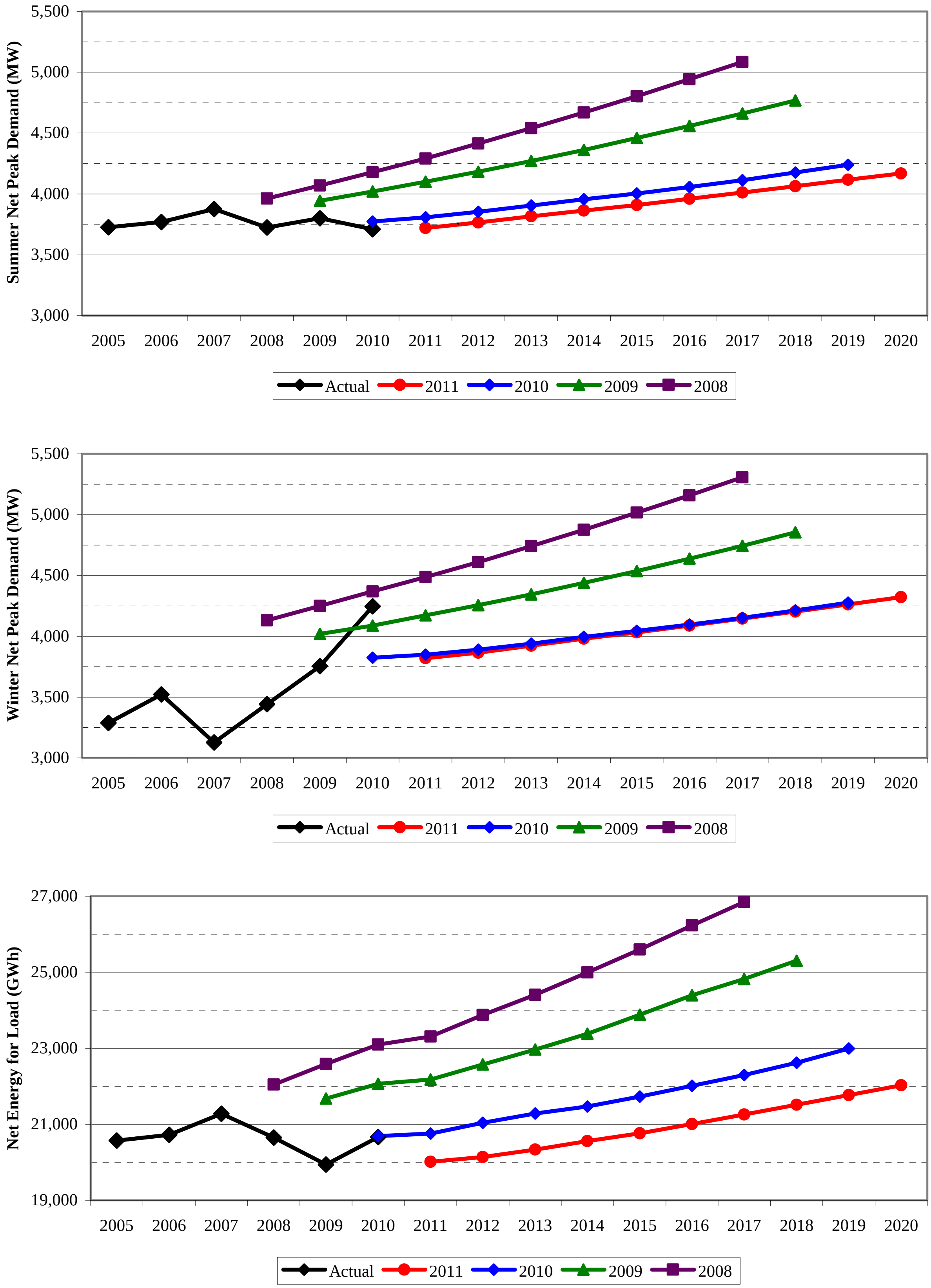
The following three graphs in Figure 24 show the actual (2005 – 2010) and forecasted (2011 – 2020) values for summer and winter peak demand and NEL. The actual winter peak demand value for 2010 appears to be higher than expected due to an unusually severe winter season.

The summer peak demand forecast is almost identical to the forecast from last year's TYSP, only shifted downward slightly. The winter peak demand forecast is virtually identical to the previous year's forecast, however, the actual values for winter peak demand have been rising each year.

The actual 2010 NEL is almost exactly equal to the 2010 forecasted value, however the 2011 forecast has the values shifted down by approximately 1,000 MW.

Analysis of TECO's historical forecast accuracy to total retail energy sales from 2006 through 2010 results in an average forecast error rate of 3.25 percent. This value shows that TECO tends to over-forecast its retail energy sales by an average of 3.25 percent. Comparison with the overall average error rate of 2.44 percent for all the TYSP utilities shows that TECO's error rate is somewhat higher than the statewide average.

**Figure 24. TECO: Demand & Energy Forecast**



## Demand-Side Management

New DSM goals were set for all the FEECA utilities in 2009. Following the goal-setting proceedings, TECO developed a new DSM Plan to implement programs based on its new goals. TECO's new DSM Plan was approved at the December 20, 2011 Commission Conference, and is included in this year's TYSP filing.

## Reliability Criteria

TECO is also one of the three IOUs which maintains a 20 percent reserve margin by stipulation. Figure 25 displays the projected reserve margin for TECO through the planning horizon for both summer and winter peak periods. As the figure shows, TECO is projecting its reserve margin to be more than sufficient for winter, and at or above the minimum level for summer throughout the ten-year period.

Figure 26 displays TECO's reserve margin when the savings resulting from the load management and interruptible components of DSM are removed from the calculations. The importance of non-firm load in a utility's planning reserve is apparent from this figure, which shows that the summer reserve margin falls below 15 percent for most of the years in the planning period.

TECO is the only IOU that currently maintains a minimum generation-only reserve margin. Because DSM programs, and especially load control and interruptible load programs are voluntary, the savings from such programs could be reduced at any time due to customers leaving the programs. In response to a data request, TECO stated that, "if the reserve margin was made up entirely from load management and interruptible customers, Tampa Electric would likely curtail non-firm load more often and in longer durations." In recognition that such a situation could result in large numbers of customers leaving the programs resulting in an unacceptably low level of reserve, TECO maintains a minimum of seven percent generation-only reserve margin. Figure 26 shows that TECO plans to maintain a generation-only reserve margin of above 10 percent for the ten-year planning horizon.

**Figure 25. TECO: Reserve Margin Projections**

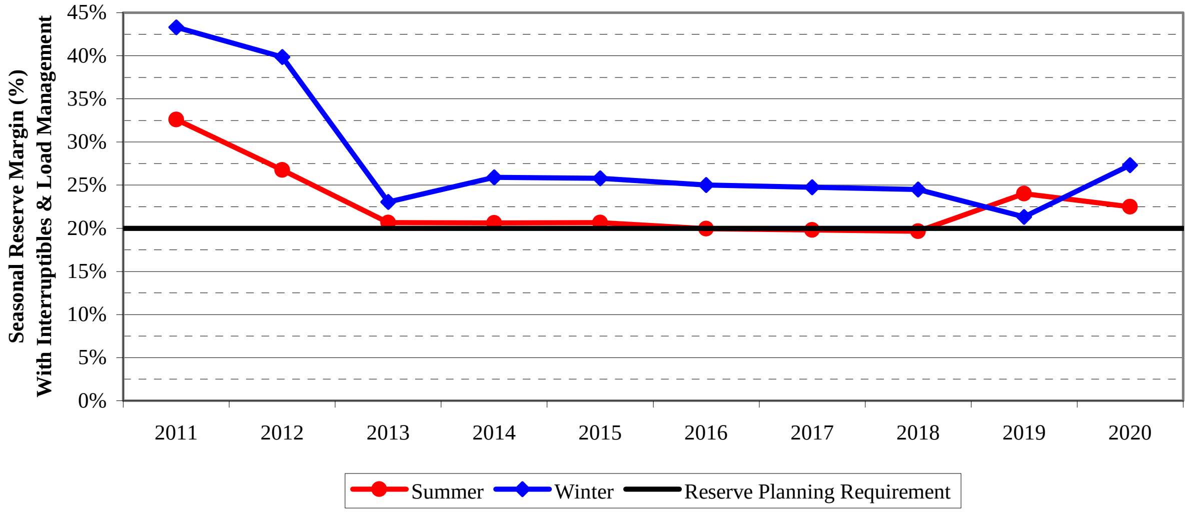
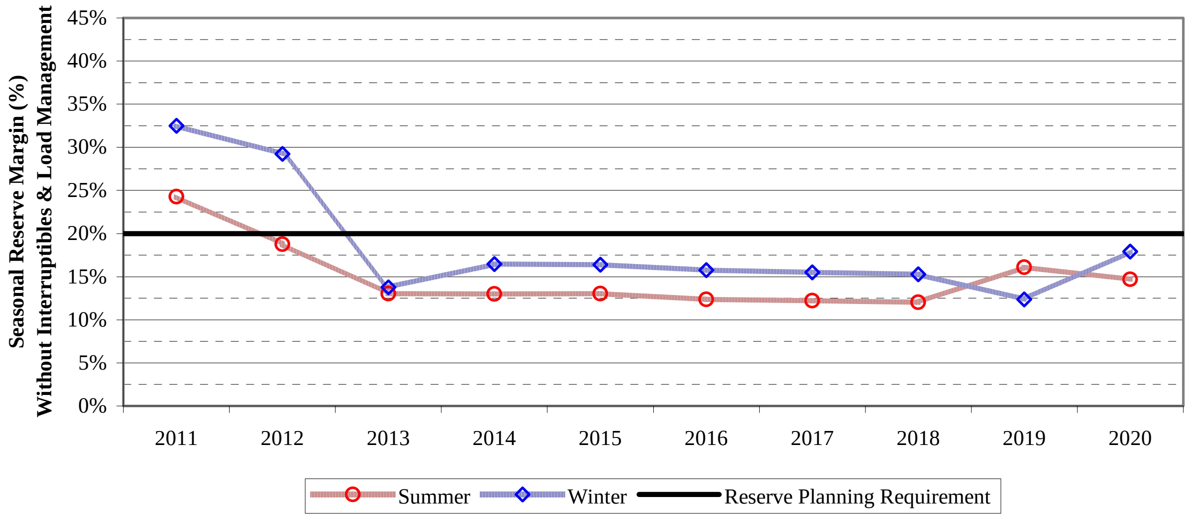


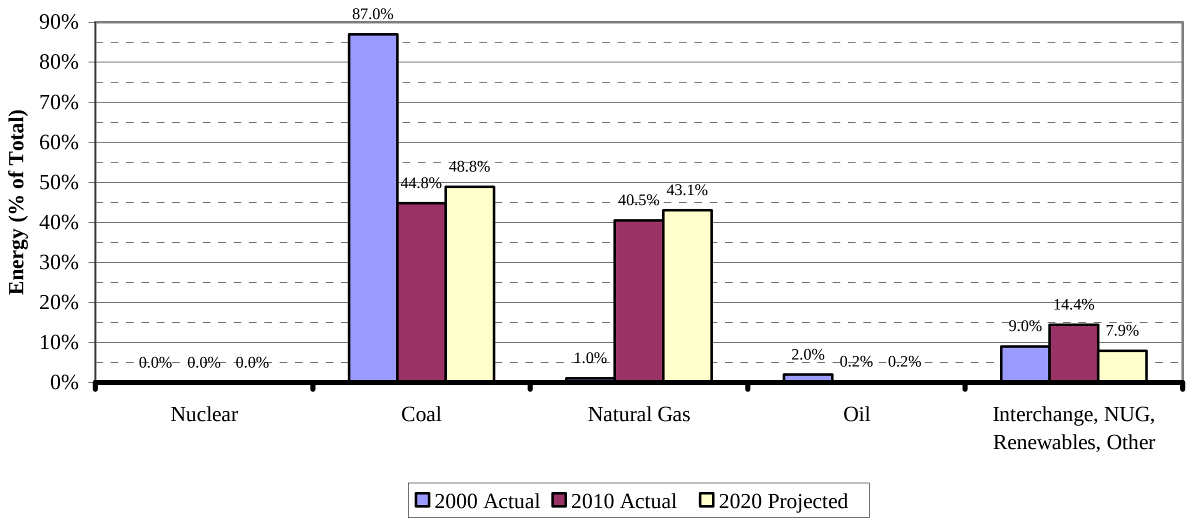

**Figure 26. TECO: Generation-Only Reserve Margin Projections**




## Fuel Diversity

Figure 27 shows that currently more than 85 percent of TECO's energy is generated by coal-fired units and natural gas-fired units. The remaining 14.7 percent comes from purchases and renewable generation, with a very small portion from oil-fired units. Over the planning horizon, the share of energy generated by both coal and natural gas is projected to increase, with the percentages of purchases and renewables decreasing.

**Figure 27. TECO: Energy Generation by Fuel Type (Percent of Total)**




Source: TECO 2001 and 2011 TYSP

## Generation Additions

Table 18 shows in detail the expansion plan included in TECO's 2011 TYSP. Three CT units are planned to become operational in 2013, and then one in each of the following five years. The CT units in 2017 and 2018 are appearing in TECO's TYSP for the first time in 2011. All of the remaining units also appeared in the 2010 Plan.

**Table 18. TECO: Generation Additions by Technology Type**

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Combustion Turbine Unit Additions** | | | | |
| Future CT 1 | 56 | n/a | n/a | 5 / 2013 |
| Future CT 2 | 56 | n/a | n/a | 5 / 2013 |
| Future CT 3 | 56 | n/a | n/a | 5 / 2013 |
| Future CT 4 | 56 | n/a | n/a | 5 / 2014 |
| Future CT 5 | 56 | n/a | n/a | 5 / 2015 |
| Future CT 6 | 56 | n/a | n/a | 5 / 2016 |
| Future CT 7 | 56 | n/a | n/a | 5 / 2017 |
| Future CT 8 | 56 | n/a | n/a | 5 / 2018 |
| **Combined Cycle Unit Additions** | | | | |
| Polk 2-5 CC 1 | 970 | None yet | None yet | 5 / 2019 |

Source: TECO 2011 TYSP

## *GULF POWER COMPANY (GULF)*

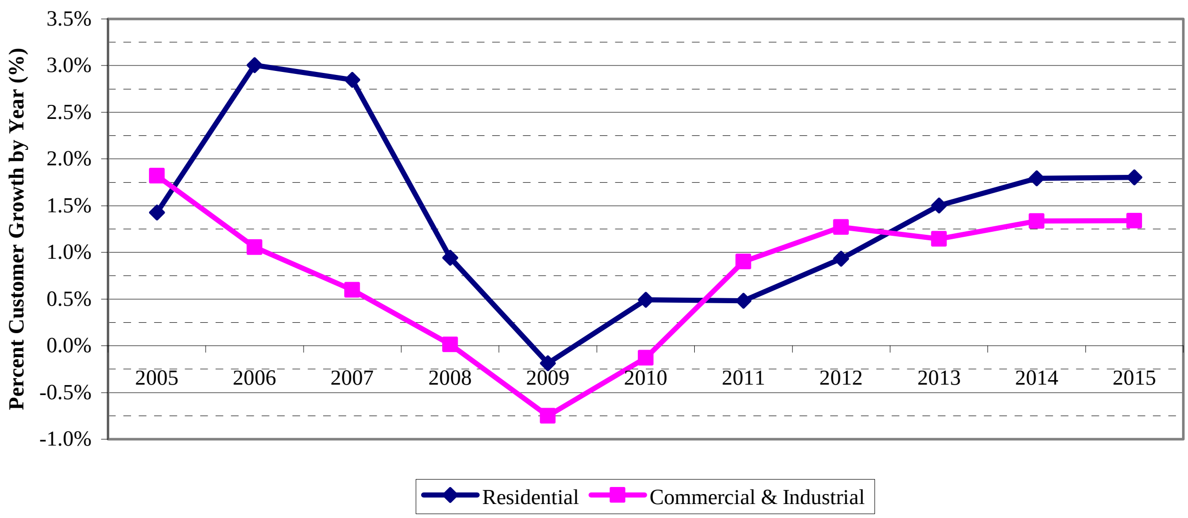
Gulf Power Company (Gulf) is the smallest of Florida's IOUs filing a Ten-Year Site Plan, in terms of generation. Gulf Power, along with Alabama Power, Georgia Power, and Mississippi Power, are members of the Southern Company electric system. Gulf is the only Florida utility that does not have the FRCC as its regional reliability entity. Because Gulf plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by the Gulf units is consumed in Florida.

In 2010, Gulf generated a total of 11,359 GWh. This figure represents 5.1 percent of the total NEL generated in Florida in 2010.

### Peak Demand and Energy Forecasts

Figure 28 shows the actual customer growth rates from 2005 through 2010, and the projected customer growth rates for 2011 through 2015. Like the other IOUs, Gulf experienced an overall loss of customer accounts during the 2005 through 2009 period, and began to see positive growth once again in 2010. Gulf also expects this positive growth to continue, although not at the historic rate seen a decade ago.

**Figure 28. GULF: Customer Growth Rates**



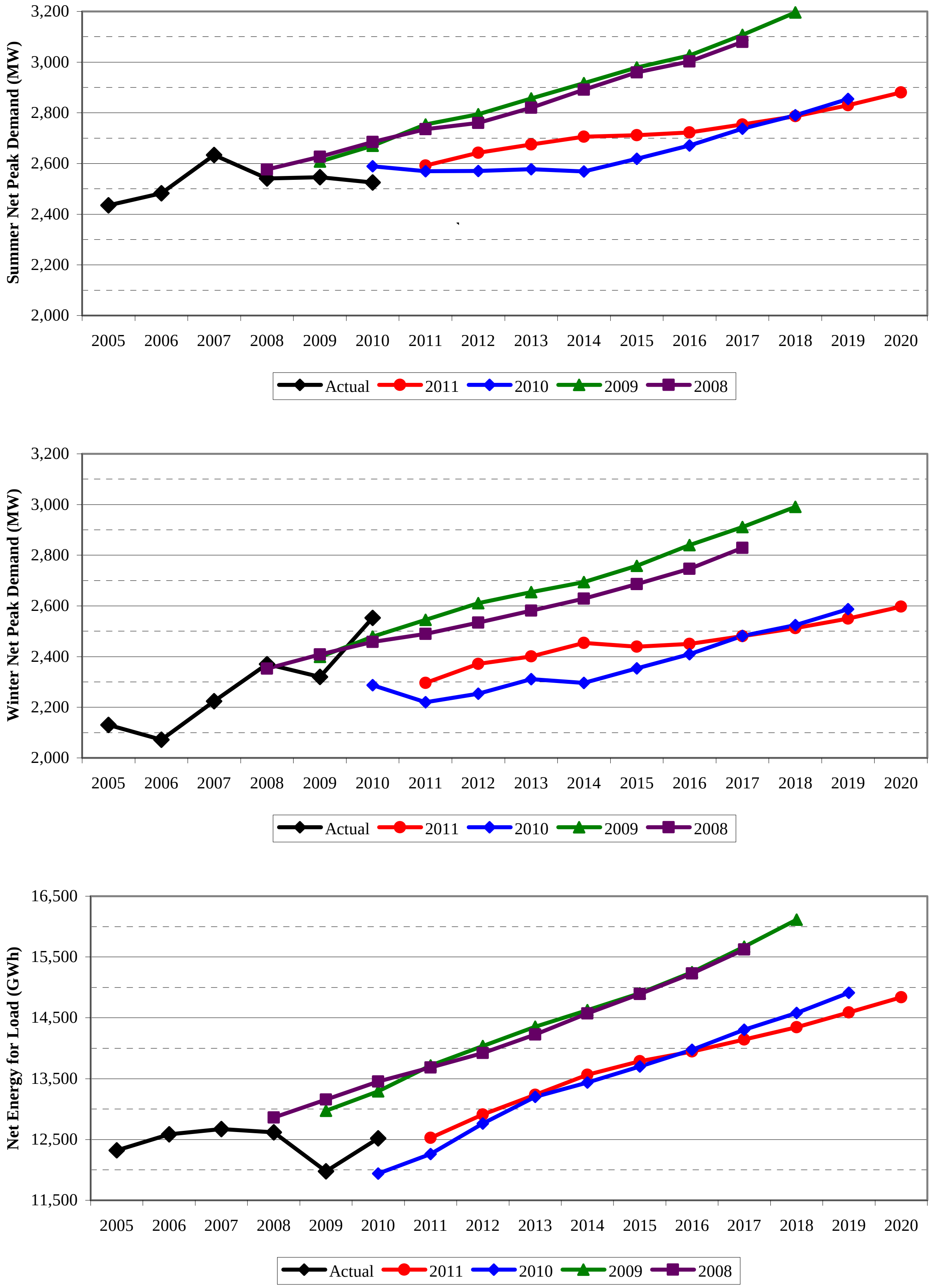

Source: Gulf 2011 TYSP

Gulf's projections for summer and winter peak demand and NEL for the planning horizon, along with the actual values for the previous five years, are shown in the three graphs in Figure 29. Like the other IOUs, Gulf's forecasts for summer and winter peak demand are very similar to the previous year's forecasts, but have been adjusted upward slightly. The actual winter peak demand value for 2010 is higher than was previously forecasted, due to an unusually severe winter season.

The forecasted NEL for the planning horizon is almost identical to the 2010 forecasted values.

Analysis of Gulf's historical forecast accuracy for total retail energy sales from 2006 through 2010 shows that the average forecast error is -0.32 percent. This value indicates that Gulf tends to under-forecast its retail energy sales by 0.32 percent. When compared to the overall average forecast error of 2.44 percent for all the TYSP utilities, Gulf's error rate is much lower.

**Figure 29. GULF: Demand & Energy Forecast**



## Demand-Side Management

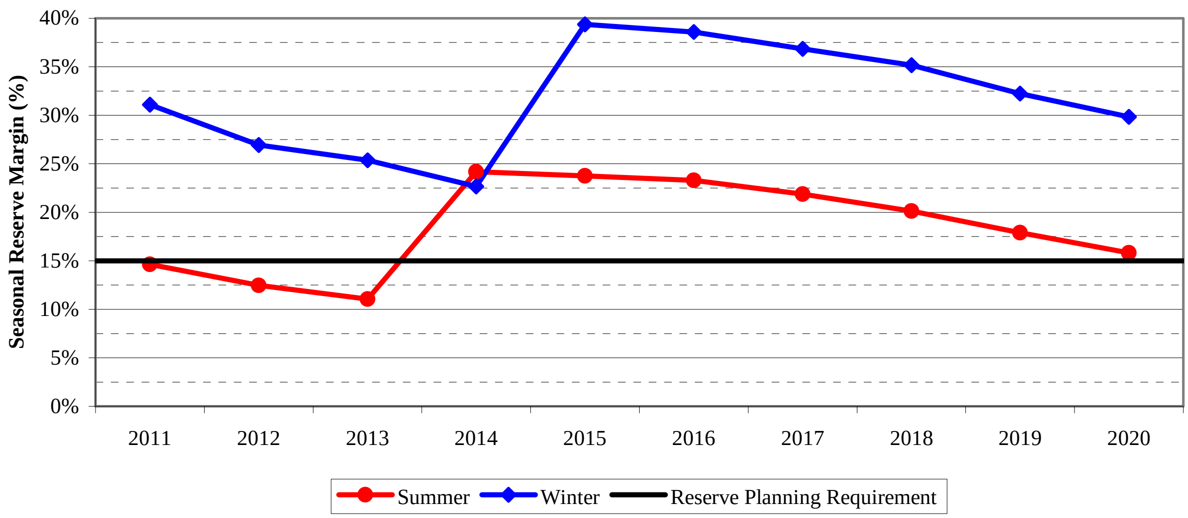
Gulf's DSM Plan, which meets the higher goals approved by the Commission in 2009, was approved by the Commission at the January 25, 2011 Commission Conference. The 2009 DSM goals are included in the values for reserve margin in the 2011 TYSP.

## Reliability Criteria

Gulf maintains a 15 percent reserve margin. Figure 30 displays Gulf's projected reserve margin for both summer and winter peak periods throughout the planning horizon. Although the reserve margin appears to be extremely low in 2013, a large firm purchased power contract will be implemented that year, which causes the reserve margin to spike upwards. Also, these figures do not include assistance from other Southern Company operating companies.

Gulf does not administer any active load management or interruptible load programs, and therefore has no non-firm load component in its reserve margin.

**Figure 30. GULF: Reserve Margin Projections**

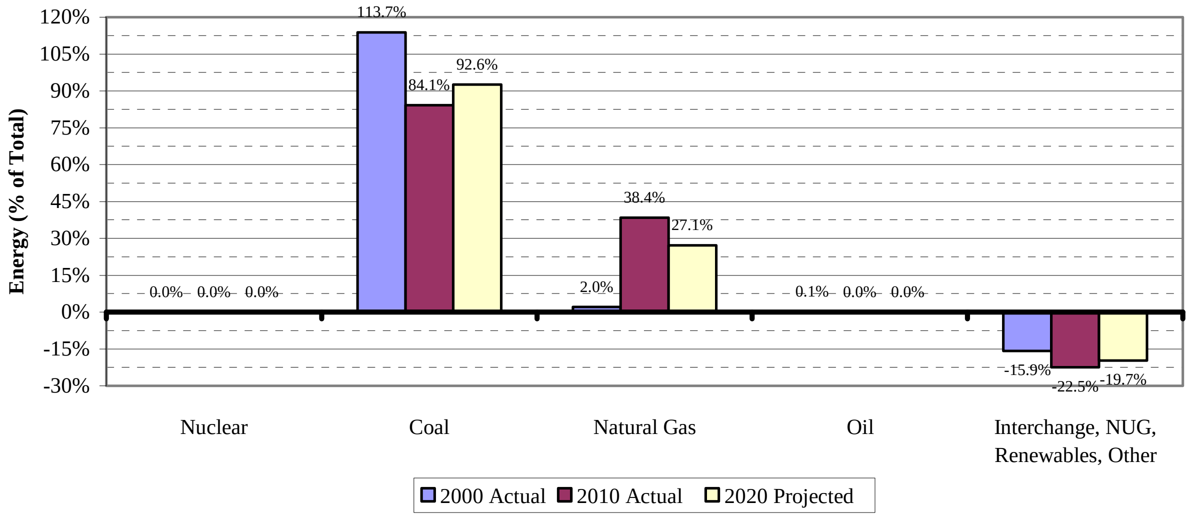



Source: Gulf 2011 TYSP

## Fuel Diversity

Figure 31 shows negative values for the interchange/other category of generation. This simply indicates that Gulf actually sold more energy than it purchased, and it expects this situation to continue over the planning horizon. Because this energy was generated and subsequently sold, the percentages of energy generated by fuel type sum to more than 100 percent.

**Figure 31. GULF: Energy Generation by Fuel Type (Percent of Total)**




Source: Gulf 2001 and 2011 TYSP

## Generation Additions

No additional generation is planned by Gulf in the current planning horizon.

# INDIVIDUAL UTILITIES

## *MUNICIPAL UTILITIES & RURAL ELECTRIC COOPERATIVES*

- **Florida Municipal Power Agency**
- **Gainesville Regional Utilities**
- **JEA**
- **City of Lakeland**
- **Orlando Utilities Commission**
- **Seminole Electric Cooperative**
- **City of Tallahassee**

# *FLORIDA MUNICIPAL POWER AGENCY (FMPA)*

FMPA is a governmental wholesale power company owned by 30 municipal electric utilities located throughout the State of Florida. FMPA facilitates opportunities for its members to participate in power supply projects developed by Florida utilities and other producers, and provides economies of scale in power generation and related services.

FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (ARP), where FMPA plans and supplies all of the power requirements for 14 of its participating utilities. The values for capacity in the following figures corresponds to the ARP.

FMPA had a total summer generating capacity of 981 MW and generated 6,299 GWh in 2010, which represents 2.5 percent of the total NEL for the state. The summer net firm peak demand was 1,272 MW in 2010.

**Peak Demand and Energy Forecasts**

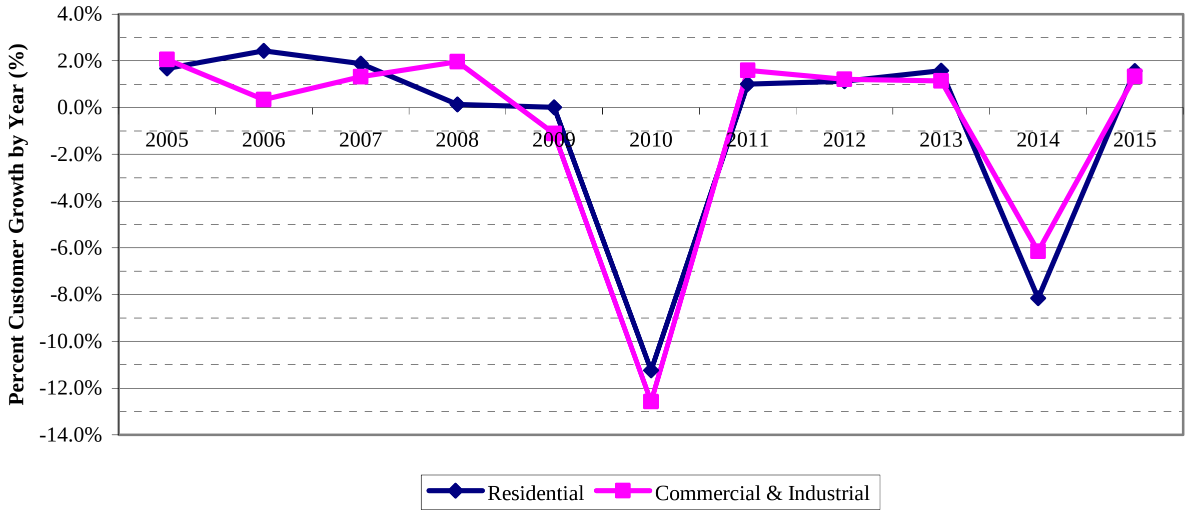
FMPA's projected NEL for 2020 is 7,341 GWh. The projected summer net firm peak demand for FMPA is projected to be 1,418 MW in 2020.

FMPA's load and energy forecasts include projections of customers, demand, and energy sales for each of the ARP participants. Forecasts are prepared for individual ARP participants, and then aggregated into projections of the total ARP demand and energy requirements.

Figure 32 displays the historical and forecasted growth rates for FMPA customers from 2005 through 2015. Regarding its forecasts, FMPA reports that historical and projected economic and demographic data were developed from data provided by commercial providers, as well as from information regarding local economic and demographic issues specific to each ARP participant.

Figure 32 shows the historic and projected rates of customer growth for FMPA for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected. The drop in the rate of growth for 2010 is due to the City of Lake Worth leaving the ARP, and the smaller drop in 2014 is the expected result of the departure of the City of Vero Beach from the ARP. The chart does not include the rate of change for the year 2015, but it would also show a drop for that year due to the City of Fort Meade leaving the ARP. These utilities will remain as members of the FMPA, but are exercising an option to modify their memberships from a full requirements basis to a partial requirements basis. These changes in membership status means that the ARP will no longer utilize these participants' generating resources, if any exist.

**Figure 32. FMPA: Customer Growth Rates**

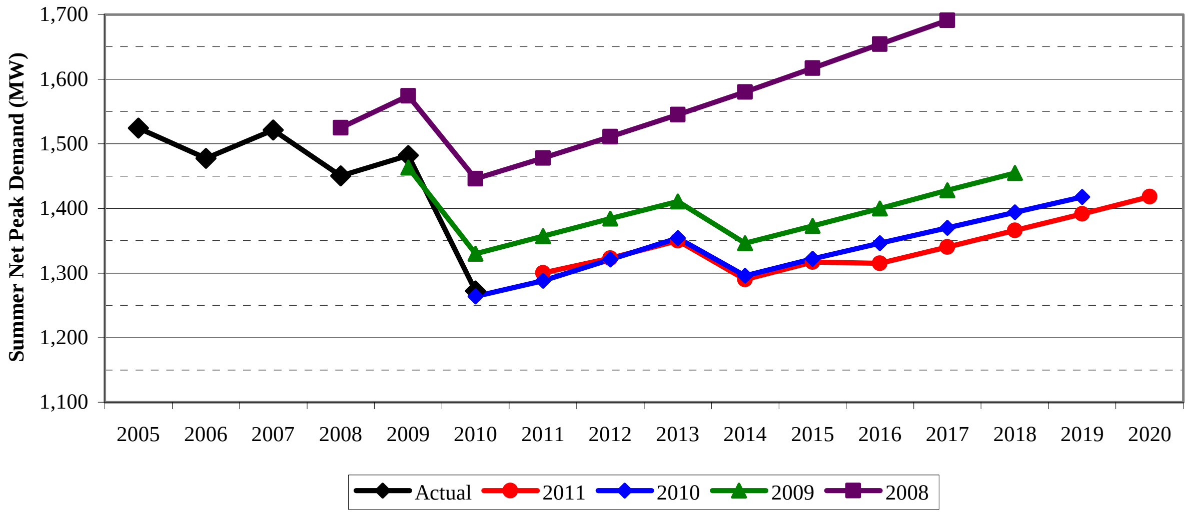


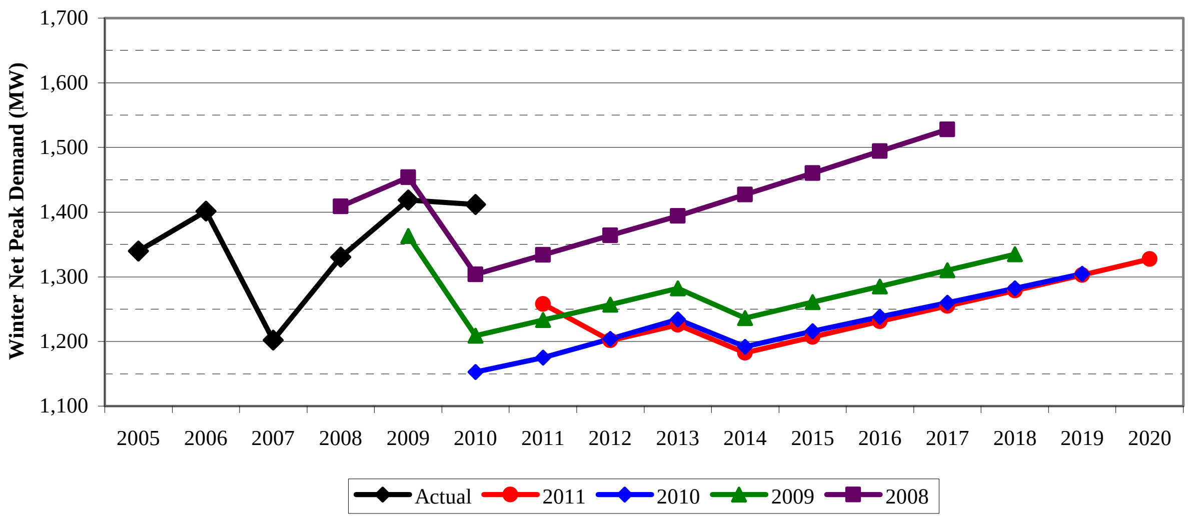

The three graphs in Figure 33 show FMPA's actual values for summer and winter peak demand, as well as the actual NEL for the previous six years. For comparison purposes, these graphs also show the forecasted values of summer and winter peak demand and NEL from the 2008, 2009, 2010, and 2011 TYSPs.

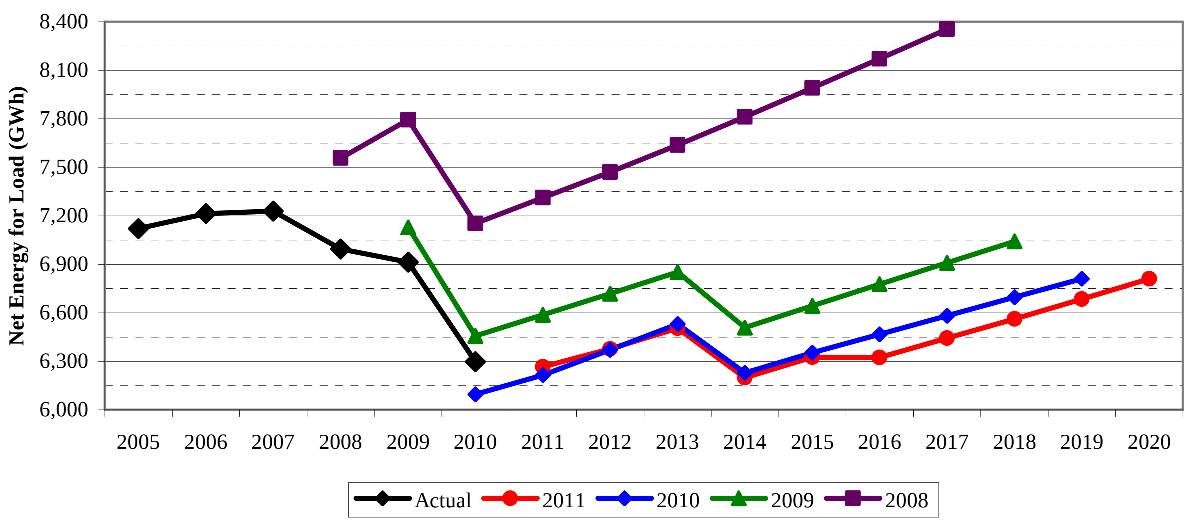
These graphs show that, along with other Florida electric utilities, the forecasts were lowered each year from 2008 to 2010, until the current cycle, which does not differ significantly from the 2010 forecast. Only the summer peak demand and the NEL forecasts have been decreased slightly in the outer years of the planning cycle.

Analysis of the historical forecast accuracy for FMPA's historical forecast accuracy for total retail energy sales for the previous five-year period shows that the average forecast error is 2.32 percent. This figure is very close to the overall average forecast error of 2.44 percent for all the TYSP utilities.

**Figure 33. FMPA: Demand & Energy Forecast**



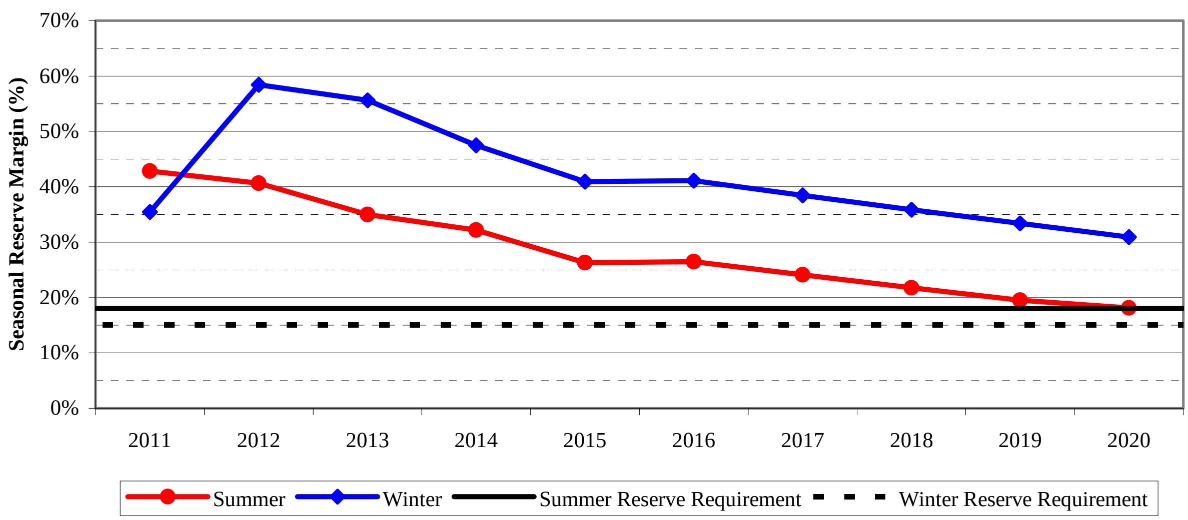
## Demand-Side Management

FMPA is not one of the FEECA utilities, and therefore is not required to meet DSM goals set by the Commission. It does, however, utilize renewable resources such as solar PV and biomass. In addition, a Conservation & Energy Efficiency Program and a Net Metering Program are offered to FMPA's customers. Because they are still in a pilot phase, the effects of the energy efficiency programs are not included in the demand and energy forecasts. FMPA does not administer load management or interruptible load programs, and therefore has no energy efficiency component added to its reserve margin.

## Reliability Criteria

FMPA maintains a 15 percent reserve margin, pursuant to FRCC requirements. Figure 34 displays FMPA's forecasted reserve margin over the planning horizon for the summer and winter seasons. As can be seen in the figure, FMPA has ample reserves and its margin only begins to approach the 15 percent minimum in the last few years of the horizon. FMPA does not administer load management or interruptible load programs, and therefore has no non-firm load component in its reserve margin.

**Figure 34. FMPA: Reserve Margin Projections**

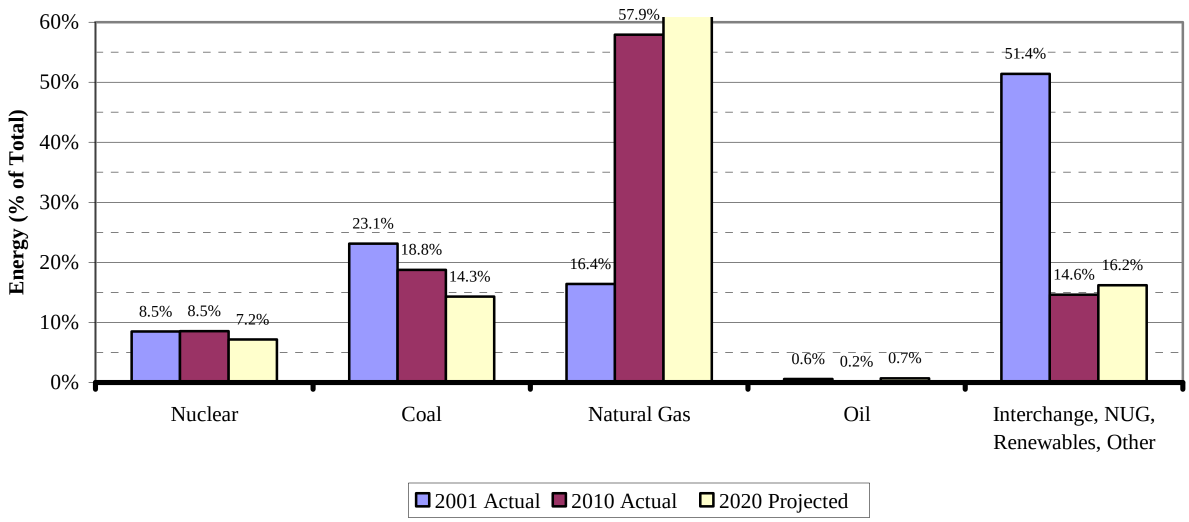



Source: FMPA 2011 TYSP

## Fuel Diversity

Figure 35 displays the composition of FMPA's system in terms of energy generated. The figure shows that FMPA is not planning to change its system significantly over the ten-year planning horizon. Small reductions in nuclear and coal-fired generation will be compensated for by increases in natural gas-fired generation and slightly more purchased power.

**Figure 35. FMPA: Energy Generation by Fuel Type (Percent of Total)**




Source: FMPA 2001 and 2011 TYSP

## Generation Additions

FMPA has only one additional generating unit in its 2011 TYSP. Cane Island Unit 4, a 300 (summer) MW natural gas-fired combined cycle generator, went in-service in May 2011.

## *GAINESVILLE REGIONAL UTILITIES (GRU)*

GRU is a municipal electric, natural gas, water, wastewater, and telecommunications utility system owned and operated by the City of Gainesville. The GRU retail electric system service area includes the City of Gainesville and its surrounding urban area.

In 2010, GRU's total NEL was 2,141 GWh, which represents 0.9 percent of the state's cumulative NEL. GRU's summer net firm peak demand in 2010 was 470 MW.

**Peak Demand and Energy Forecasts**

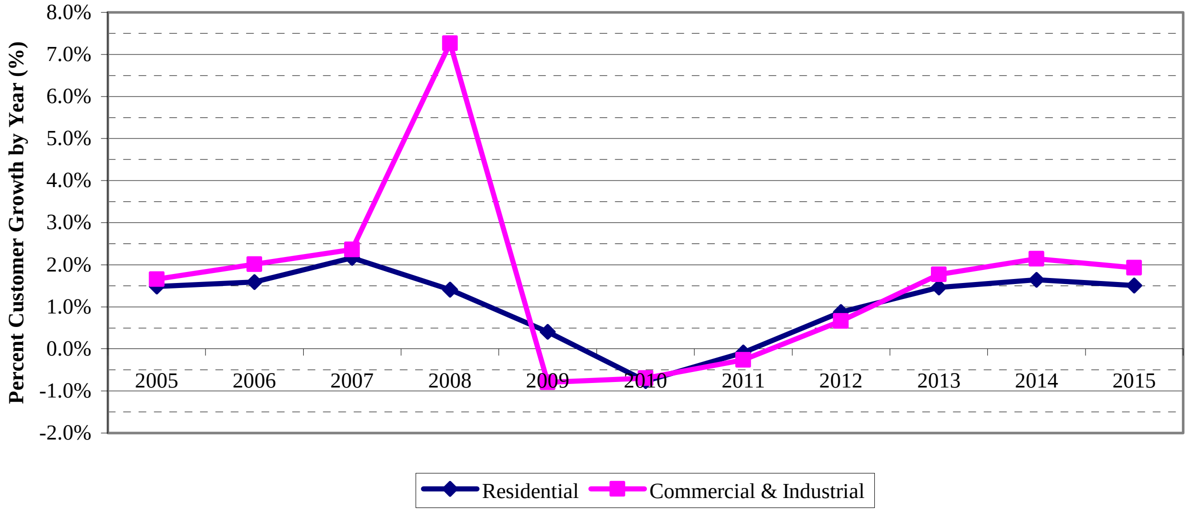
GRU projects that its summer net firm peak demand will increase to 481 MW in 2020. The NEL forecasted for 2020 is 2,206 GWh.

GRU's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. Figure 36 shows the historic and projected rates of customer growth for GRU for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

GRU separates its customers into several classes: residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay (SEC), and sales to Alachua (City of Alachua). The "Commercial & Industrial" category in Figure 36 represents all of the classes listed above except the residential class.

The rate of growth in commercial and industrial customers in Figure 36 appears to spike dramatically in 2008. In fact, there was an increase of about 700 non-residential customers that year.

**Figure 36. GRU: Customer Growth Rates**



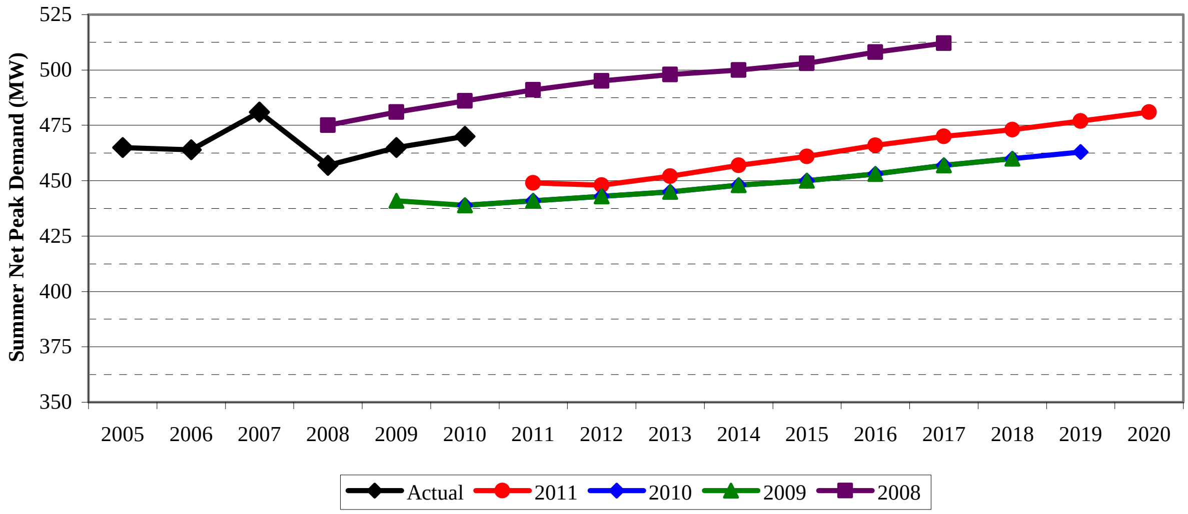

The three graphs in Figure 37 show the actual values for GRU's summer and winter peak demand, and its NEL from 2005 through 2010. While the summer peak demand and NEL remained fairly consistent, the winter peak demand spiked upwards in both 2009 and 2010. This spike is presumably due to the unusually severe cold spells experienced in the region for both of those winter seasons.

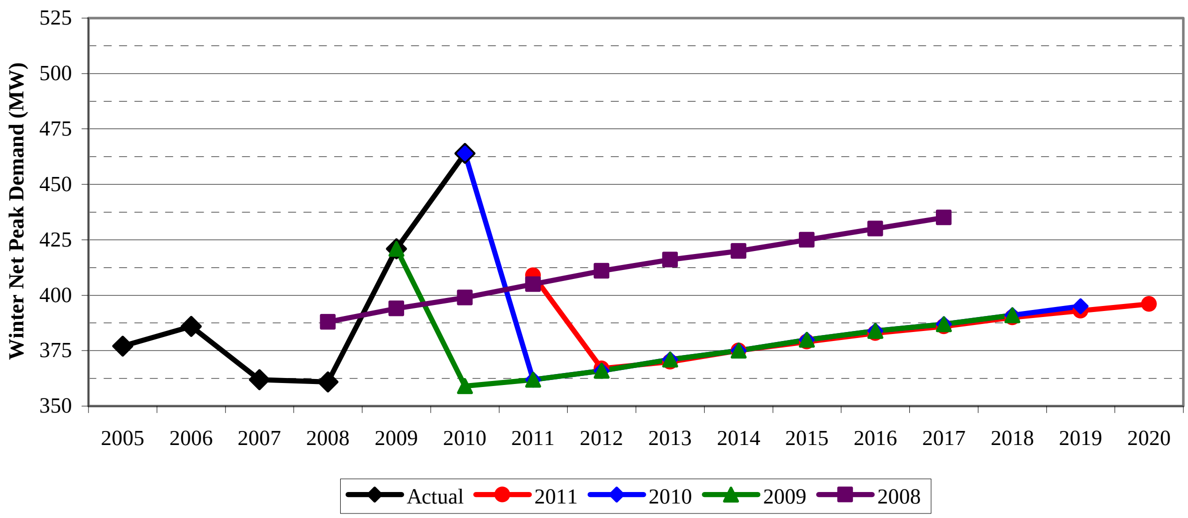
Figure 37 also illustrates the forecasted seasonal peak demands and NEL for 2008, 2009, and 2010, as well as the current 2011 forecasts. The summer peak demand forecast was adjusted slightly upwards in 2011. The winter peak demand forecast has been virtually identical for the past three cycles, except that it appears GRU is expecting another unusually cold winter this year.

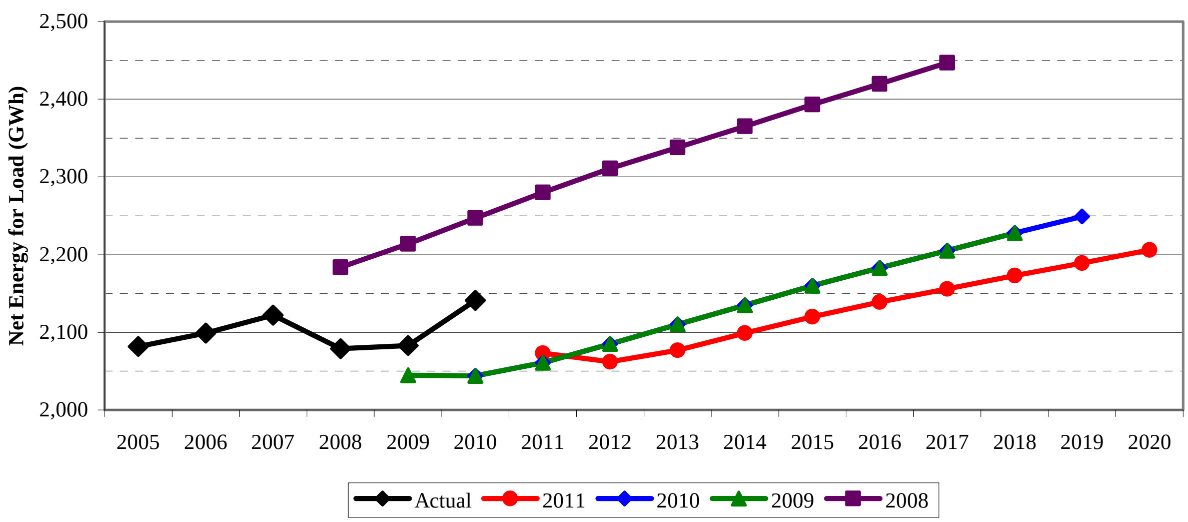
The NEL forecasts for 2009 and 2010 were identical, and the 2011 forecast for NEL has been adjusted downward slightly.

Analysis of the historical forecast accuracy for GRU's total retail energy sales from 2006 through 2010 results in an average forecast error of 1.98 percent. This figure denotes GRU's tendency to slightly over-forecast its retail energy sales, but it compares well to the overall average forecast error of 2.44 percent for all the TYSP utilities.

**Figure 37. GRU: Demand & Energy Forecast**



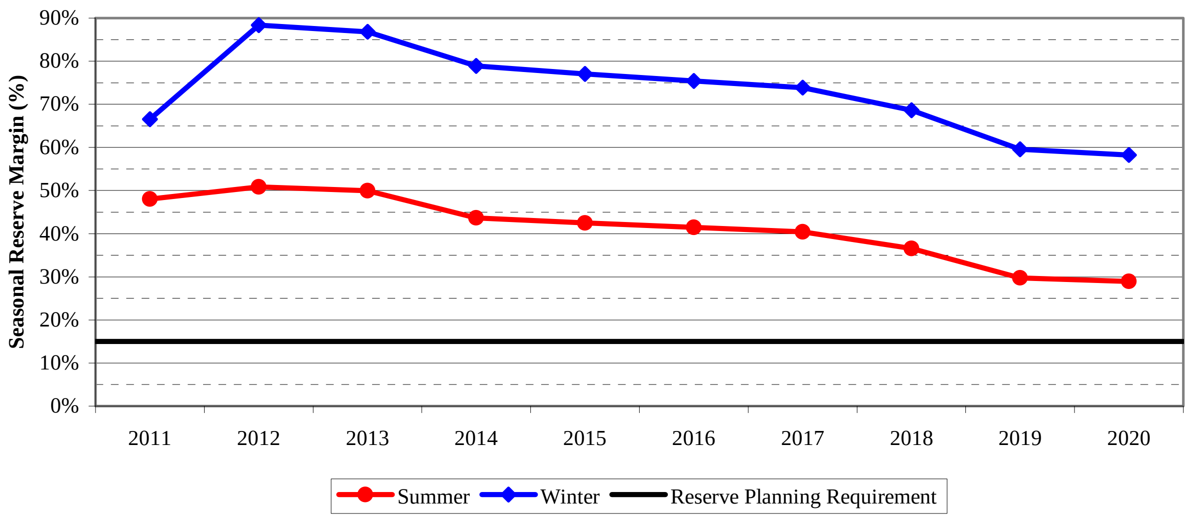
## Demand-Side Management

Because GRU does not meet the minimum criterion of annual energy sales of at least 2,000 GWh, GRU is not subject to the FEECA requirement to meet DSM goals set by the Commission. GRU does have a DSM program, however, as well as solar generation, biomass facilities, and distributed generation systems. GRU expects that its DSM programs planned for 2011-2020 will provide 27 MW of summer peak reduction, and a total of 138 GWh of annual energy savings by 2020.

## Reliability Criteria

Pursuant to FRCC requirements, GRU maintains a 15 percent reserve margin. As Figure 38 clearly shows, GRU's reserve margin is forecasted to remain well above the minimum level throughout the planning horizon for the summer and winter peak seasons. GRU does not have any active load management or interruptible load programs and therefore has no non-firm load component to its reserve margin.

**Figure 38. GRU: Reserve Margin Projections**

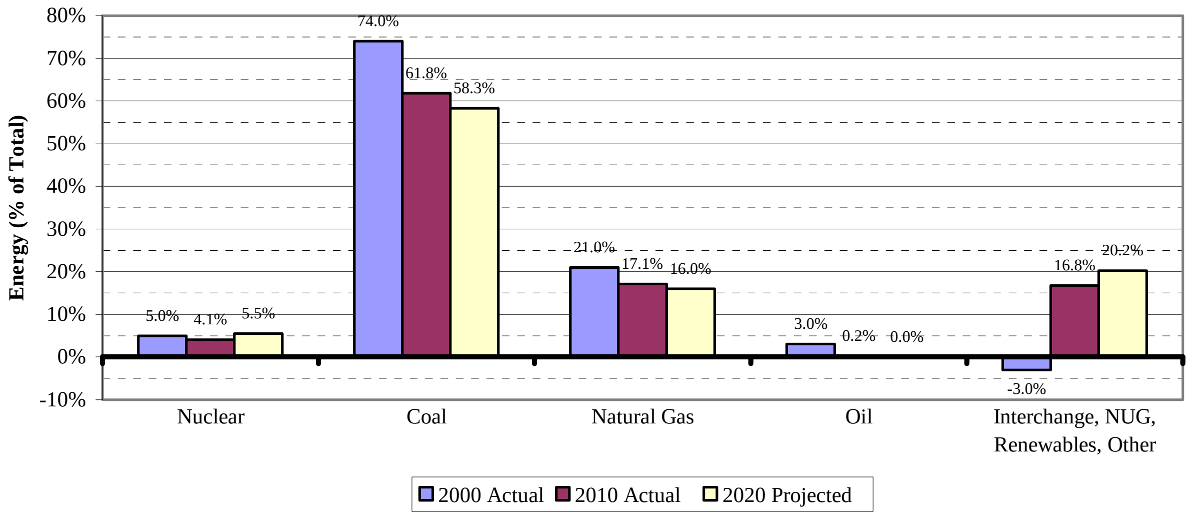



Source: GRU 2001 and 2011 TYSP

## Fuel Diversity

Figure 39 shows GRU's system composition in terms of energy generated. The figure shows that GRU expects to increase its generation from renewable sources significantly, while reducing the amount of purchased power. The amount of energy generated from nuclear is forecasted to remain stable, but the energy generated from both coal and natural gas is expected to decrease notably.

**Figure 39. GRU: Energy Generation by Fuel Type (Percent of Total)**




Source: GRU 2011 TYSP

## Generation Additions

GRU has no plans for additional generating units for the current planning horizon.

# *JEA*

JEA is a municipally owned electric utility with a service area including all of Duval County as well as portions of Clay and St. Johns Counties. Serving approximately 420,000 customers makes JEA the eighth largest municipal electric utility in the United States in terms of number of customers.

JEA had a total summer net firm generating capacity of 2,817 MW and generated 13,842 GWh in 2010, which makes up 5.6 percent of the total NEL for the State of Florida.

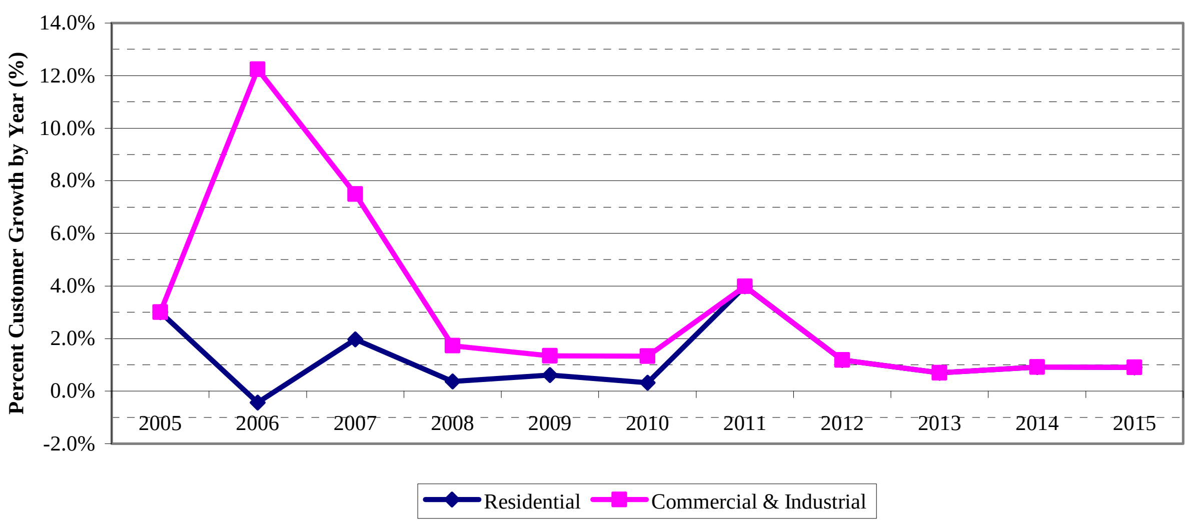
## Peak Demand and Energy Forecasts

JEA forecasts that in 2020, its summer net firm peak demand will increase to 3,290 and it will generate 16,009 GWh.

JEA's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. Figure 40 shows the historic and projected rates of customer growth for JEA for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

An increase of approximately 4,500 customers occurred in JEA's commercial/industrial class in 2006. A smaller increase in both residential and commercial/industrial classes is expected to occur in 2011.

**Figure 40. JEA: Customer Growth Rates**

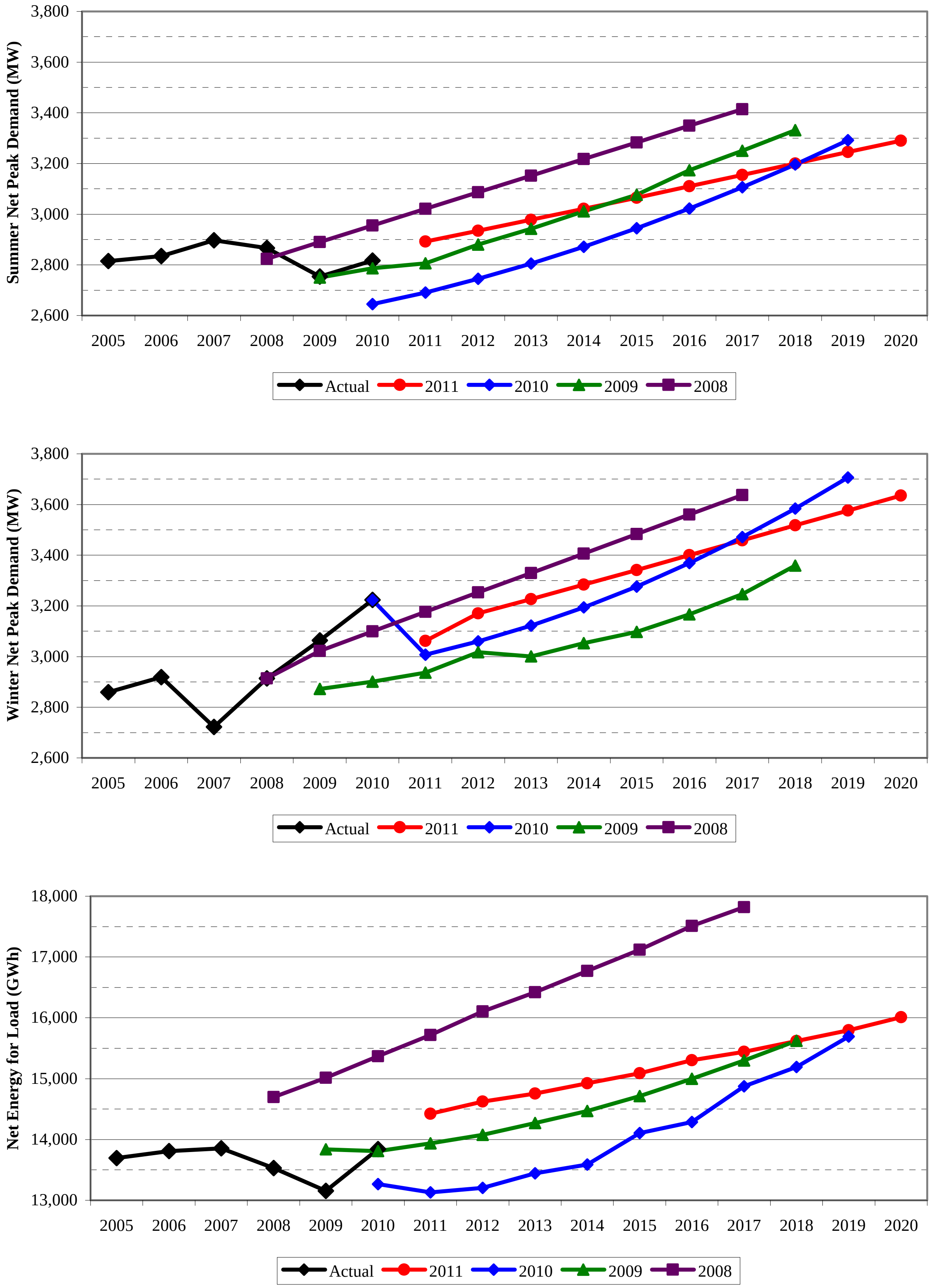


The following three graphs in Figure 41 show the actual summer and winter peak demand and NEL for the years 2005 through 2010. Both the summer peak demand and NEL are fairly consistent, while the winter peak demand spiked upwards for the past two winter seasons, which were colder than usual.

The forecasts for seasonal peak demand and NEL which appeared in the 2008, 2009, and 2010 TYSPs are also shown, as well as the current 2011 forecasts. After being adjusted downwards for three consecutive years, in 2011 the forecasts for summer peak demand and NEL were both adjusted upwards, to a level similar to the 2009 forecasts. The winter peak demand forecast was increased somewhat more than that of summer peak demand.

Analysis of the historical forecast accuracy for JEA’s total retail energy sales from 2006 through 2010 yields an average forecast error of 3.63 percent. This figure is slightly higher than the average forecast error of 2.44 percent for all the TYSP utilities. The positive number denotes a tendency to over-forecast.

**Figure 41. JEA: Demand & Energy Forecast**



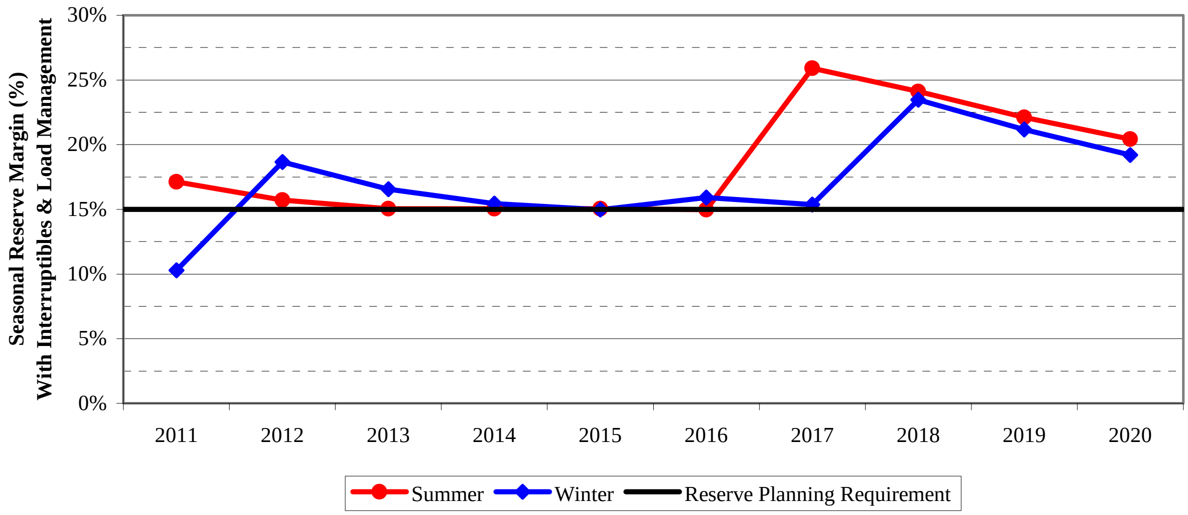
## Demand-Side Management

JEA is one of only two Florida municipal electric utilities to meet the FEECA criterion of 2,000 GWh in annual energy sales (the other is OUC). The Commission set new DSM goals for JEA in 2009, and JEA subsequently submitted a new DSM Plan designed to meet the higher demand and energy goals. JEA's DSM Plan was approved by the Commission at the September 14, 2010 Commission Conference, and the demand and energy savings resulting from the new DSM Plan are included in the 2011 TYSP filing.

## Reliability Criteria

JEA maintains a minimum reserve margin of 15 percent as part of the FRCC region. Figure 42 shows that JEA's reserve margin hovers at the 15 percent level until 2016, when it increases to above 20 percent for both the summer and winter seasons. Increased purchased capacity and decreased exported capacity cause the reserve to increase in 2016.

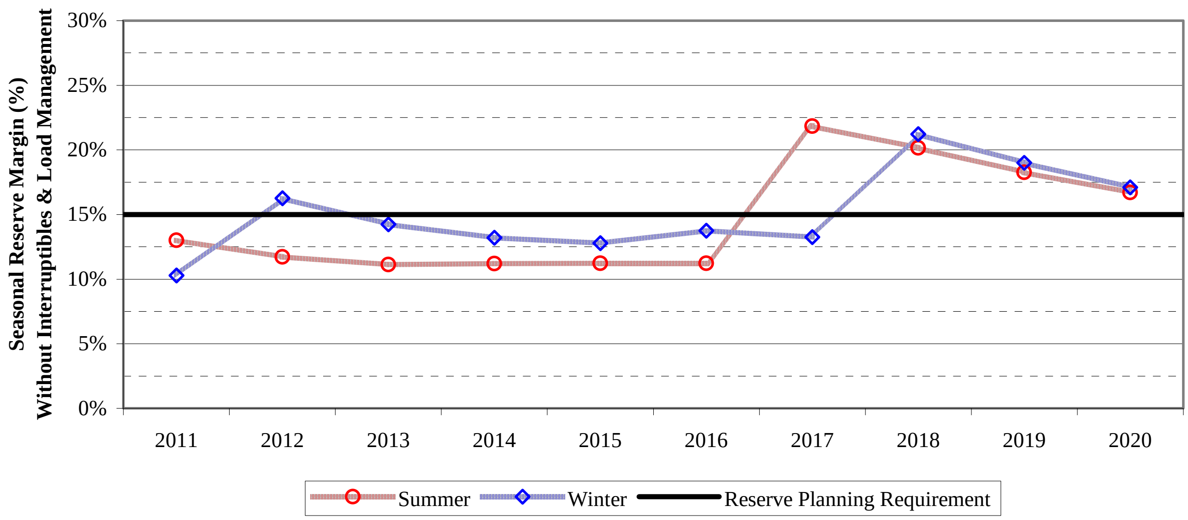
**Figure 42. JEA: Reserve Margin Projections**




Source: JEA 2011 TYSP

Because JEA does have active load management and interruptible load programs in place, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in Figure 43. Clearly, JEA's reserve margin from supply-side resources will not be less than 10 percent.

**Figure 43. JEA: Generation-Only Reserve Margin Projections**

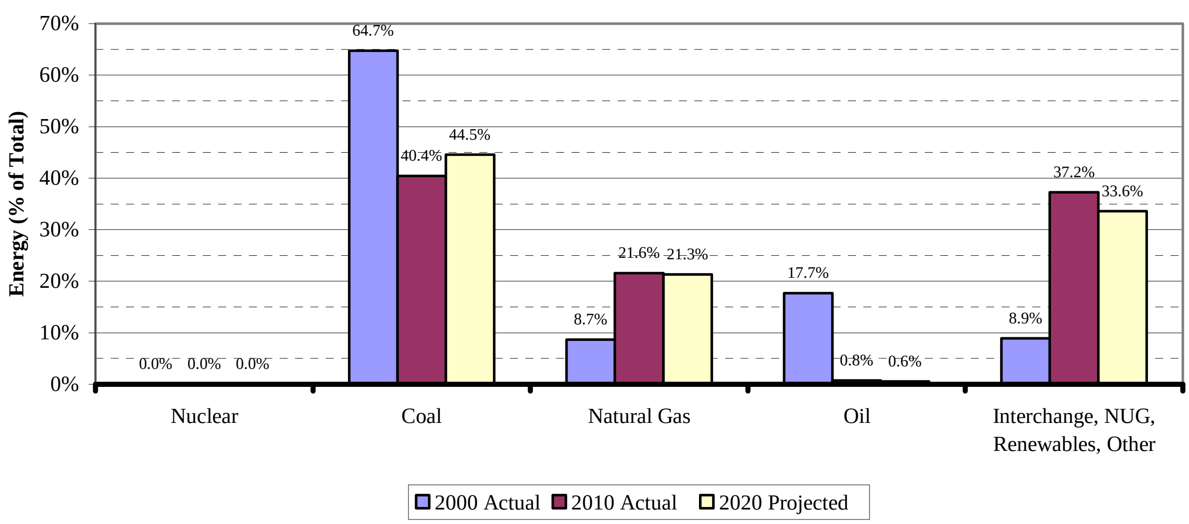



Source: JEA 2011 TYSP

## Fuel Diversity

Figure 44 illustrates JEA's historic, current, and projected system composition in terms of energy generation. The amount of energy generated by coal units is not expected to change appreciably in the next ten years, and by the end of the current planning horizon the portions of energy purchased and generated by natural gas will approximate their respective 2010 values.

**Figure 44. JEA: Energy Generation by Fuel Type (Percent of Total)**




Source: JEA 2001 and 2011 TYSP

## Generation Additions

There are no new generating units in JEA's 2011 Ten-Year Site Plan.

# *CITY OF LAKELAND (LAK)*

Lakeland Electric (LAK) is the municipal electric utility owned and operated by the City of Lakeland. Lakeland Electric is a member of the Florida Municipal Power Pool (FMPP), along with OUC and the FMPA's All-Requirements Project (ARP). The FMPP operates as an hourly energy pool with all FMPP capacity from its members committed and dispatched together. Each member of the FMPP retains the responsibility of adequately planning it own system to meet native load and FRCC reserve requirements.

Lakeland is normally a winter peaking utility, and expects to continue having its system peak demand occur during winter months based on expected normal weather. The 2010 NEL was 3,063 GWh, which represents 1.3 percent of the state's total NEL for 2010. Lakeland's winter net firm peak demand in 2010 was 709 MW

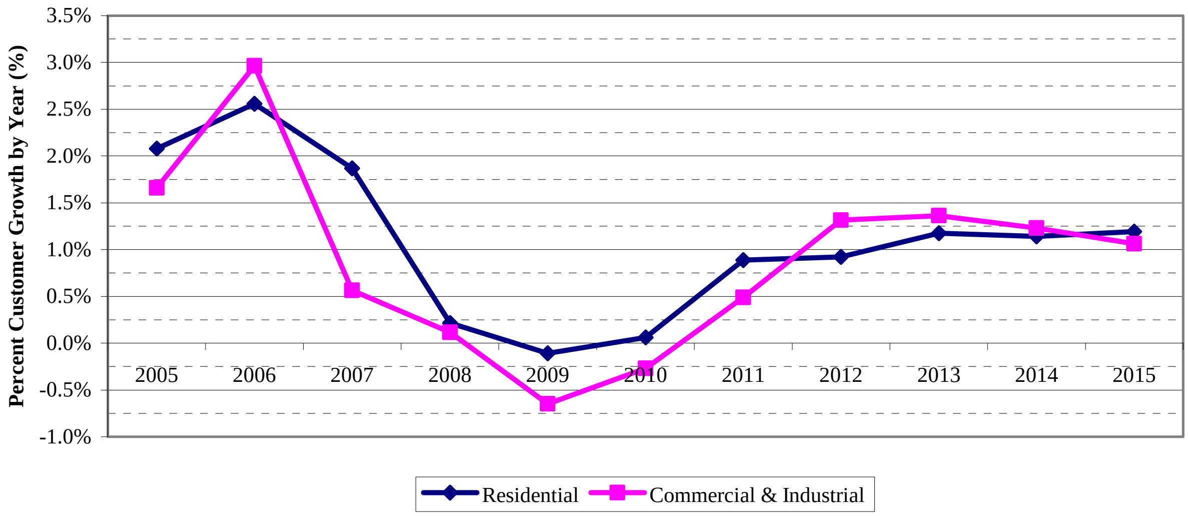
**Peak Demand and Energy Forecasts**

LAK's forecasted NEL for 2020 is 3,319 GWh, and the winter net firm peak demand is expected to reach 793 MW in 2020.

Lakeland's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. Figure 45 shows the historic and projected rates of customer growth for LAK for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

Figure 45 shows the variation in the rates of customer growth over the past five years. This variation is most likely a result of the economic conditions affecting much of the country during this time frame. However, the projected growth rates are more stable. Lakeland expects positive customer growth in both the residential and commercial/industrial classes for the next two years, and a fairly constant level of growth for the following three years.

**Figure 45. LAK: Customer Growth Rates**

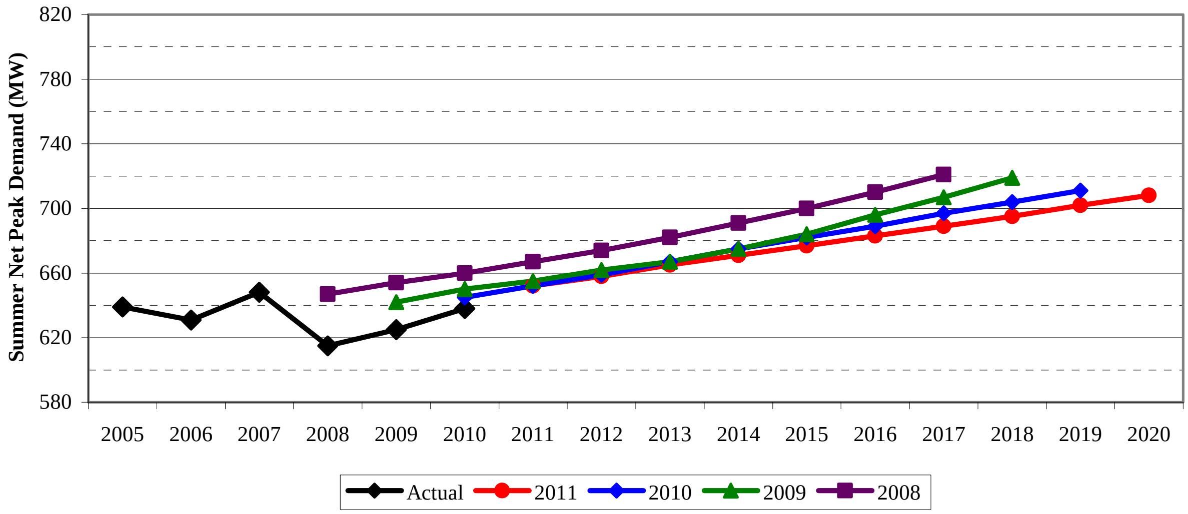


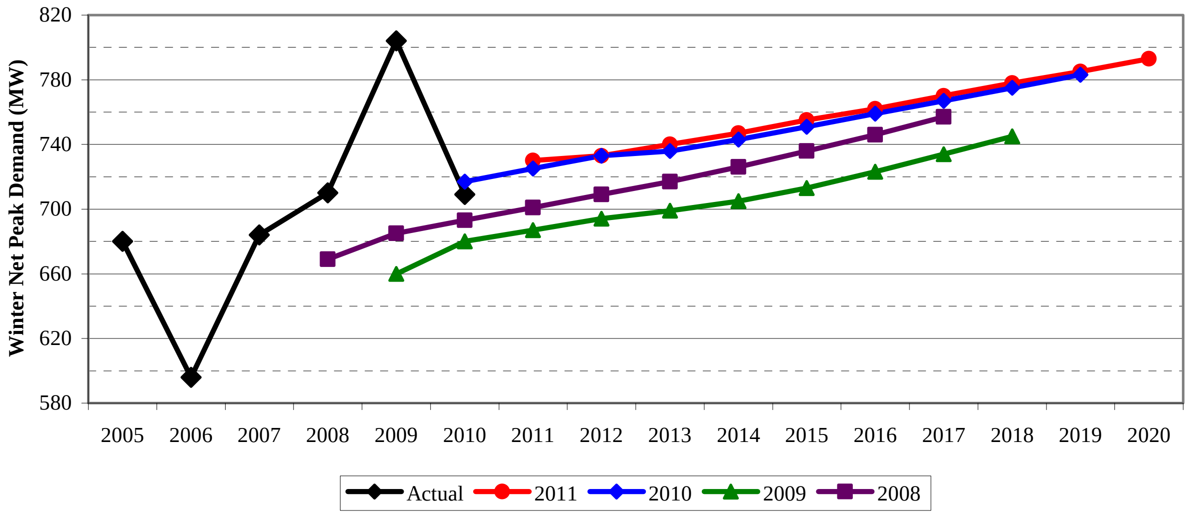

The following three graphs in Figure 46 illustrate LAK's actual summer and winter peak demand and NEL for the years 2005 through 2010. Similar to other utilities, the summer peak demand and NEL were more consistent than the winter peak demand, which fluctuated over the six-year period shown in the graph.

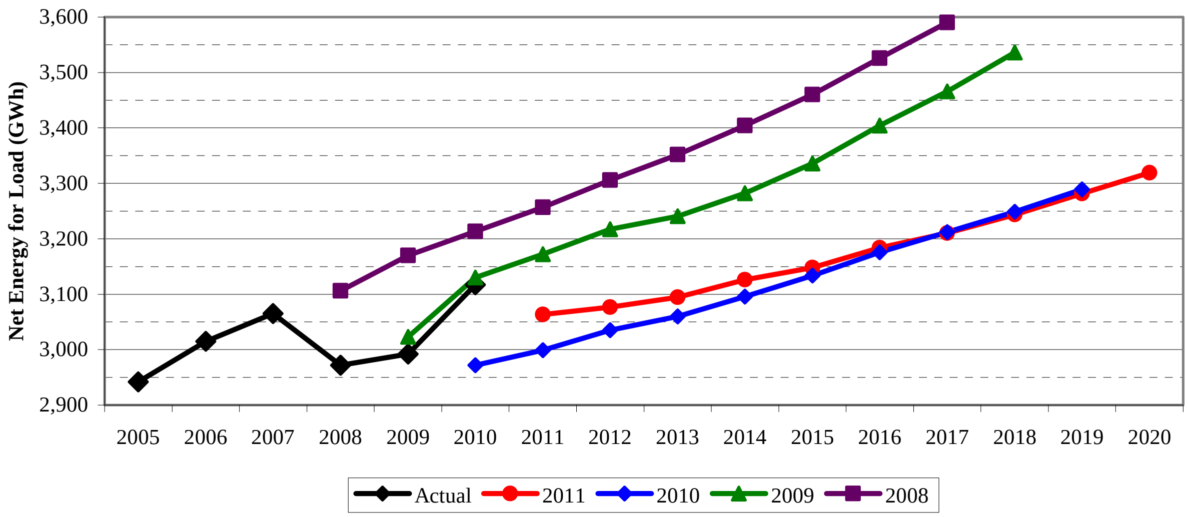
The figure also shows the forecasted values for seasonal peak demand and NEL in the past three TYSPs, as well as the current 2011 forecasts. The 2011 forecasts are very similar to the forecasts from 2010, and the winter season demand forecast for 2011 is practically identical to that from 2010. Unlike most other utilities, the winter demand forecasts for both 2011 and 2010 are higher than the forecast for the 2008 plan year.

Analysis of Lakeland's historical forecast accuracy for total retail energy sales from 2006 through 2010 shows that the average forecast error is 4.49 percent. This value indicates that Lakeland tends to over-forecast its retail energy sales by 4.49 percent. When compared to the overall average forecast error of 2.44 percent for all the TYSP utilities, Lakeland's average error rate is somewhat higher.

**Figure 46. LAK: Demand & Energy Forecast**



## Demand-Side Management

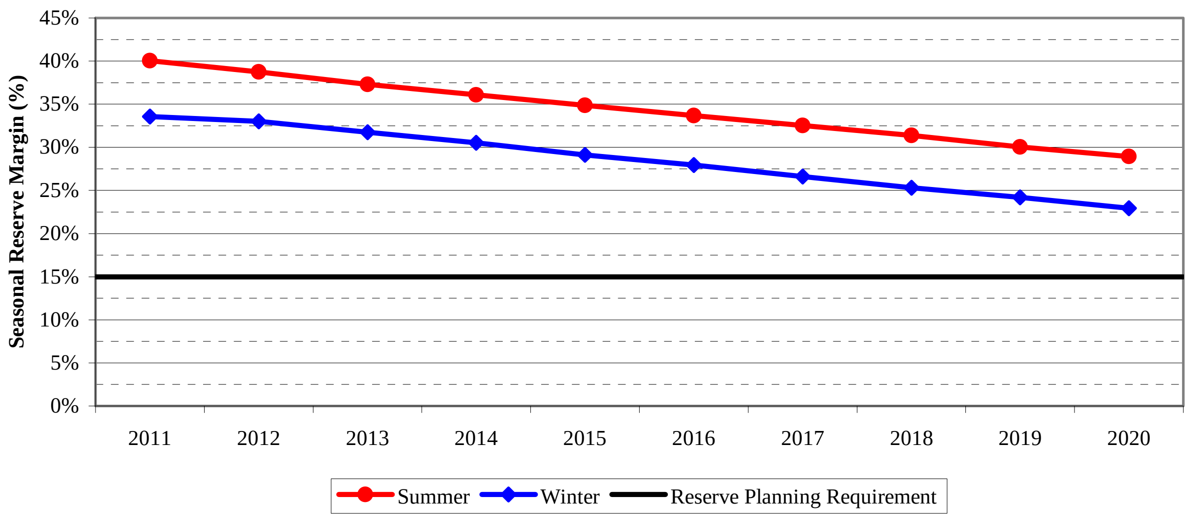
Although Lakeland does not fall under the requirements of FEECA, and therefore is not subject to Commission-set DSM goals, it does have an extensive Energy Conservation & Management Program. In addition, Lakeland administers programs with solar PV systems installed on school rooftops, and solar water heaters installed at customers' homes.

LAK does not include in its DSM program active load management and interruptible load programs that could be incorporated into its reserve margin as non-firm load.

## Reliability Criteria

As an FRCC utility, Lakeland maintains a 15 percent minimum reserve margin. As Figure 47 shows, although Lakeland's reserve margin decreases steadily over the planning horizon, it remains well above the minimum level of 15 percent.

**Figure 47. LAK: Reserve Margin Projections**

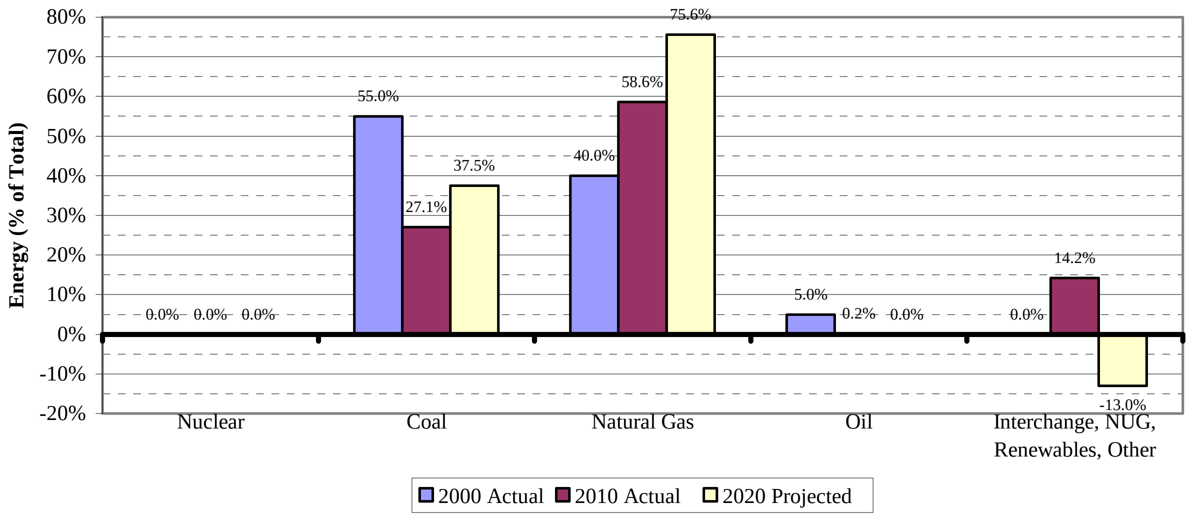



Source: LAK 2011 TYSP

## Fuel Diversity

Figure 48 shows the makeup of Lakeland's system in terms of energy generated. The figure illustrates the fact that the percentage of Lakeland's total energy generation that will come from coal and natural gas is expected to increase over the planning horizon. However, this increase will not come from new units, but rather from varying the utilizations of existing units.

**Figure 48. LAK: Energy Generation by Fuel Type (Percent of Total)**




Source: LAK 2001 and 2011 TYSP

## Generation Additions

Lakeland is not planning to add any new generating units in the current planning horizon.

## *ORLANDO UTILITIES COMMISSION (OUC)*

Orlando Utilities Commission (OUC) is a statutory commission created by the Florida Legislature as a separate part of the government of the City of Orlando. OUC is a member of the Florida Municipal Power Pool, along with Lakeland Electric and the FMPA All-Requirements Project (ARP).

OUC's total NEL for 2010 was 6,878 GWh, which represents 2.8 percent of the state total NEL. OUC's summer net firm demand in 2010 was 1,292 MW.

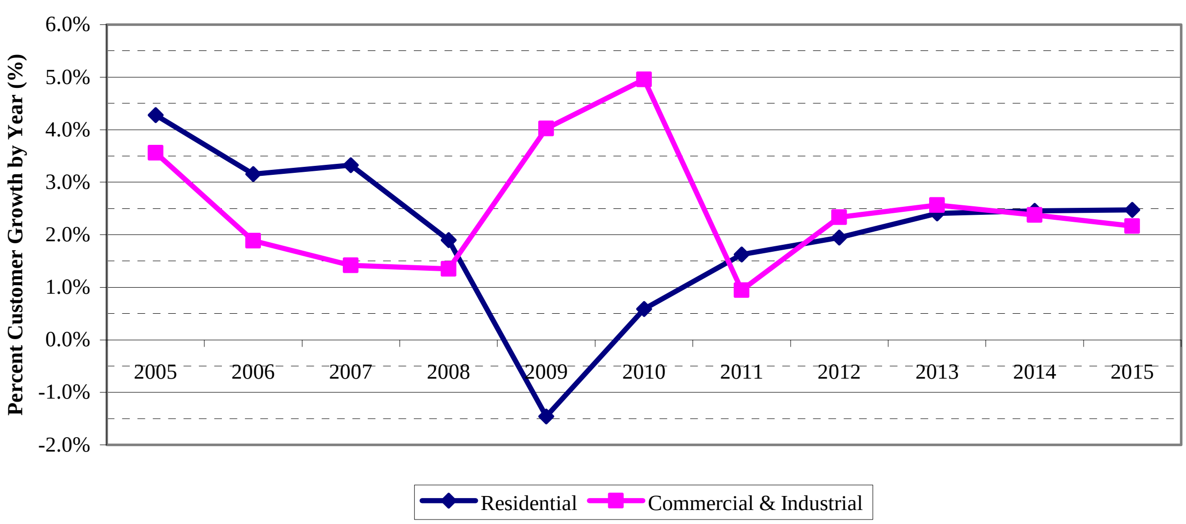
**Peak Demand and Energy Forecasts**

OUC's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. The NEL for OUC is expected to increase to 8,414 GWh in 2020, and the summer net firm demand is forecasted to be 1,678 MW in 2020.

Figure 49 shows the historic and projected rates of customer growth for OUC for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

OUC's rate of growth for residential customers declined until 2010 when it became positive, a trend that OUC expects to continue with a leveling off in the latter years of the window. The commercial/industrial customer growth rate has been rising for the past two years, but is expected to be negative in 2011 and, like the residential rate, be positive and level in the later years.

**Figure 49. OUC: Customer Growth Rates**

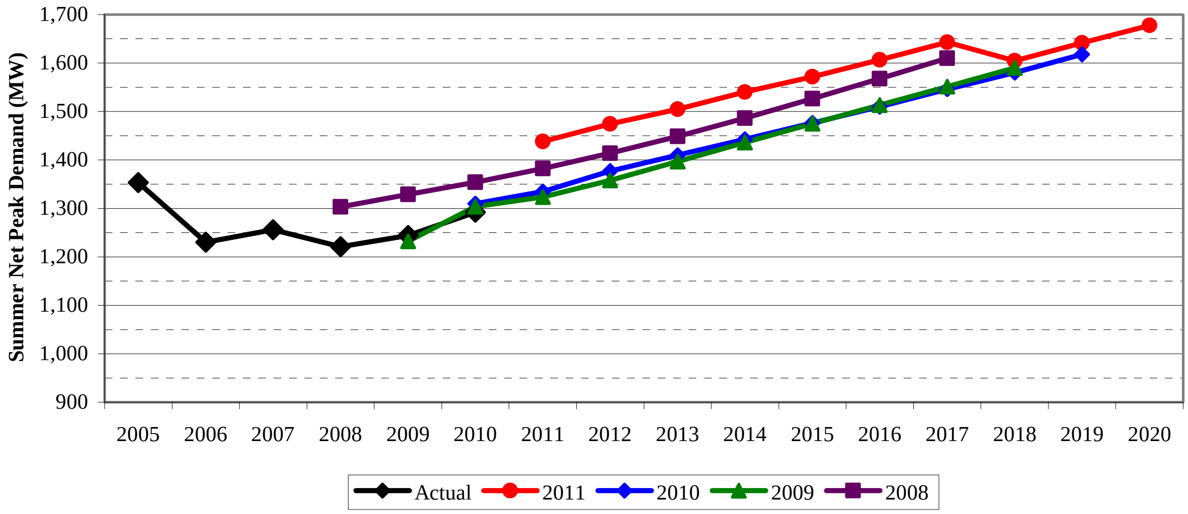


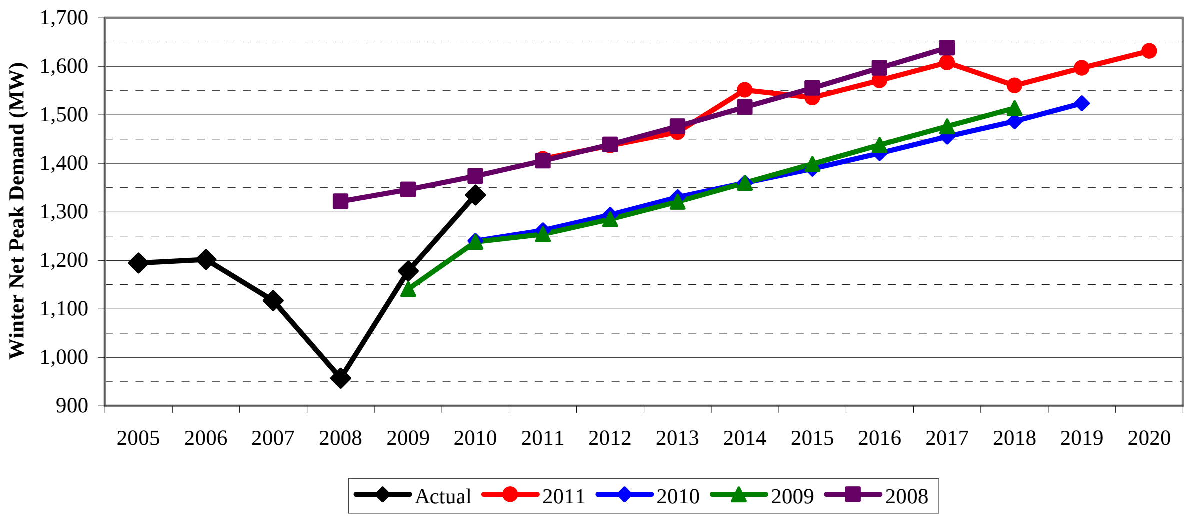
The three graphs in Figure 50 show the actual values for OUC's summer and winter peak demand and its NEL from 2005 through 2010. The summer peak demand leveled off after decreasing in 2006. The winter peak demand decreased each year through 2008, then increased in 2009 and again in 2010. The NEL decreased in 2005, was level for the next four years, then increased in 2010.

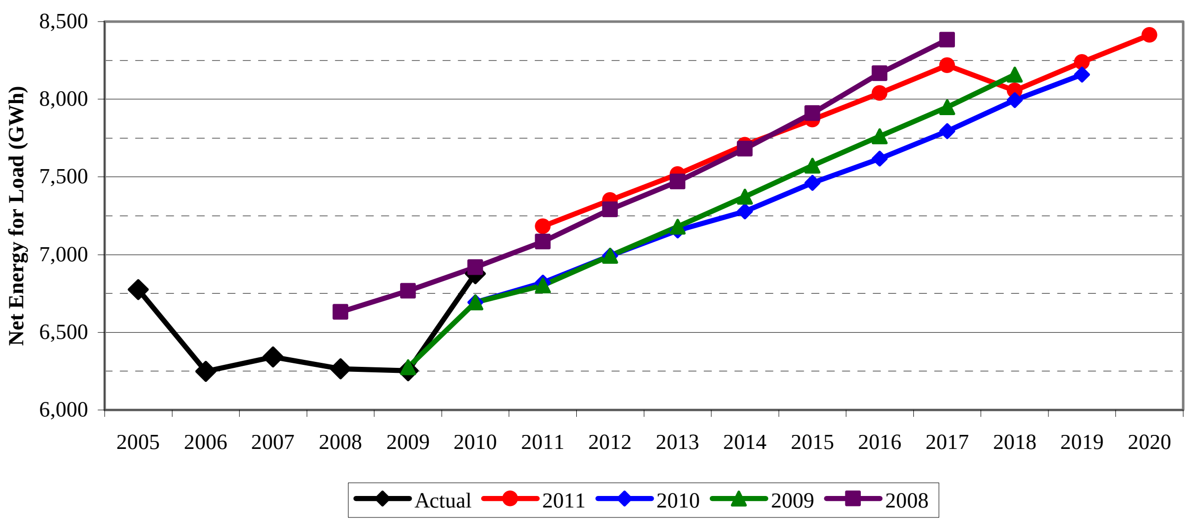
Figure 50 also illustrates the forecasted seasonal peak demands and NEL for 2008, 2009, and 2010, as well as the current 2011 forecasts. Both the summer and winter peak demand forecasts and the NEL forecast were lowered in 2009, and the 2010 forecasts were all very similar to those in 2009. However, in 2011 the summer peak demand forecast was increased to a level slightly above that for 2008, while both the winter peak demand and NEL 2011 forecasts are very similar to the 2008 values.

Analysis of the historical forecast accuracy for OUC's total retail energy sales from 2006 through 2010 results in an average forecast error of 2.92 percent. This figure denotes OUC's tendency to slightly over-forecast its retail energy sales, but it compares well to the overall average forecast error of 2.44 percent for all the TYSP utilities.

**Figure 50. OUC: Demand & Energy Forecast**



## Demand-Side Management

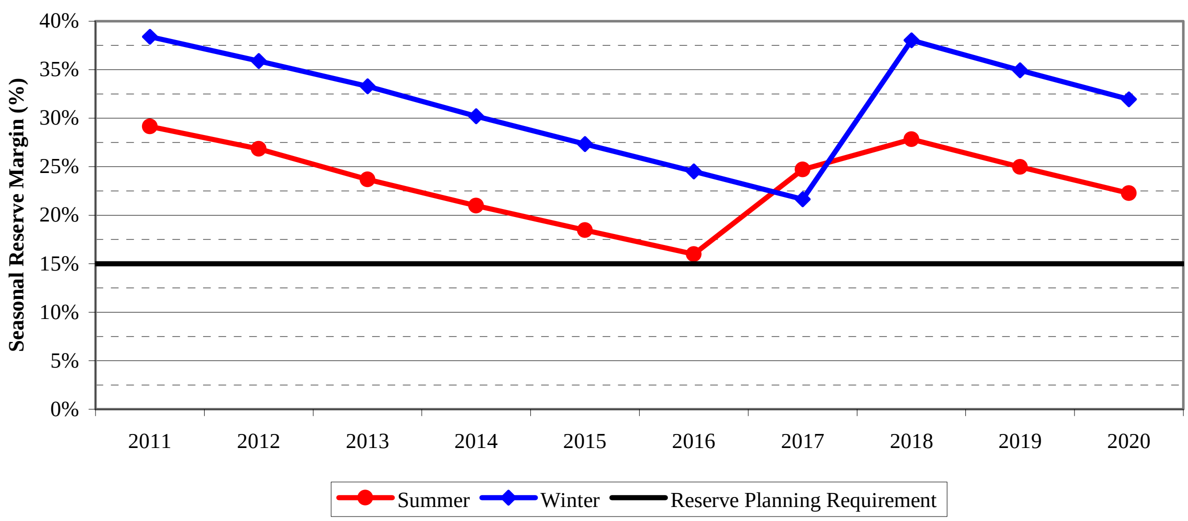
OUC is the second of the two municipal electric utilities that are subject to FEECA requirements and therefore must meet Commission-set DSM goals (the other is JEA). The Commission set new DSM goals for OUC in 2009, and OUC subsequently submitted a new DSM Plan designed to meet these new goals. OUC's DSM plan was approved at the August 31, 2010 Commission Conference.

OUC does not have active load management and interruptible load programs as part of its DSM program, and therefore has no energy efficiency component included in its reserve margin.

## Reliability Criteria

OUC maintains a 15 percent reserve margin pursuant to FRCC requirements. Figure 51 displays the summer and winter reserve margin forecasts for the current planning horizon. As the figure shows, the reserve margin decreases steadily until 2016, where the summer reserve margin approaches the 15 percent minimum level. In its 2011 TYSP, OUC shows a new generating unit coming into service in 2017, which accounts for the increased reserve margin at that time.

**Figure 51. OUC: Reserve Margin Projections**

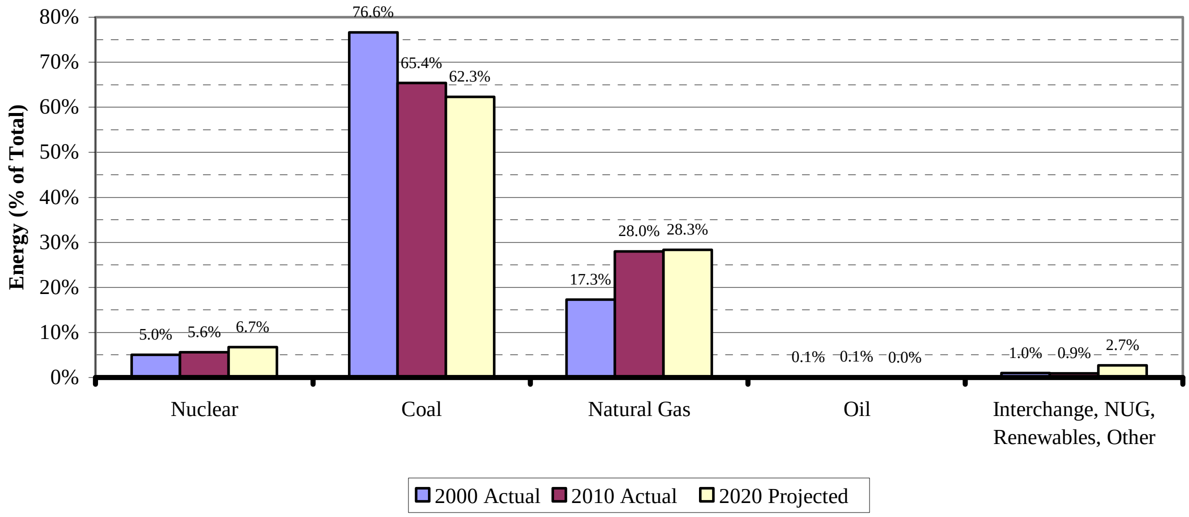



Source: OUC 2011 TYSP

## Fuel Diversity

The composition of OUC's system in terms of energy generated is displayed in Figure 52. The figure shows that OUC is not planning to change the composition of its generation system in any significant way throughout the planning horizon.

**Figure 52. OUC: Energy Generation by Fuel Type (Percent of Total)**




Source: OUC 2001 and 2011 TYSP

## Generation Additions

Based on its reserve margin calculations, OUC has determined that additional generation would be needed by 2017 in order to maintain a minimum level of reserve capacity. In order to satisfy this projected reserve margin requirement, OUC has assumed that a simple cycle combustion turbine would be constructed at its Stanton Energy Center. However, OUC will continue to evaluate alternative options and has made no commitment to construct the unit.

**Table 19. OUC: Generation Additions by Technology Type**

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Combustion Turbine Unit Additions** | | | | |
| Stanton Energy Center CT | 185 | n/a | n/a | 4/2017 |

Source: OUC 2011 TYSP

## *SEMINOLE ELECTRIC COOPERATIVE (SEC)*

Seminole Electric Cooperative, Inc. (SEC) is a corporation that provides electric power to its ten distribution members' systems. These members are all regional cooperatives that purchase power from SEC under long-term wholesale power contracts. SEC serves its members' loads with a combination of owned and purchased power resources.

SEC had a total summer net firm generating capacity of 3,548 MW and generated 17,346 GWh in 2010, which makes up 7.0 percent of the total NEL for the State of Florida.

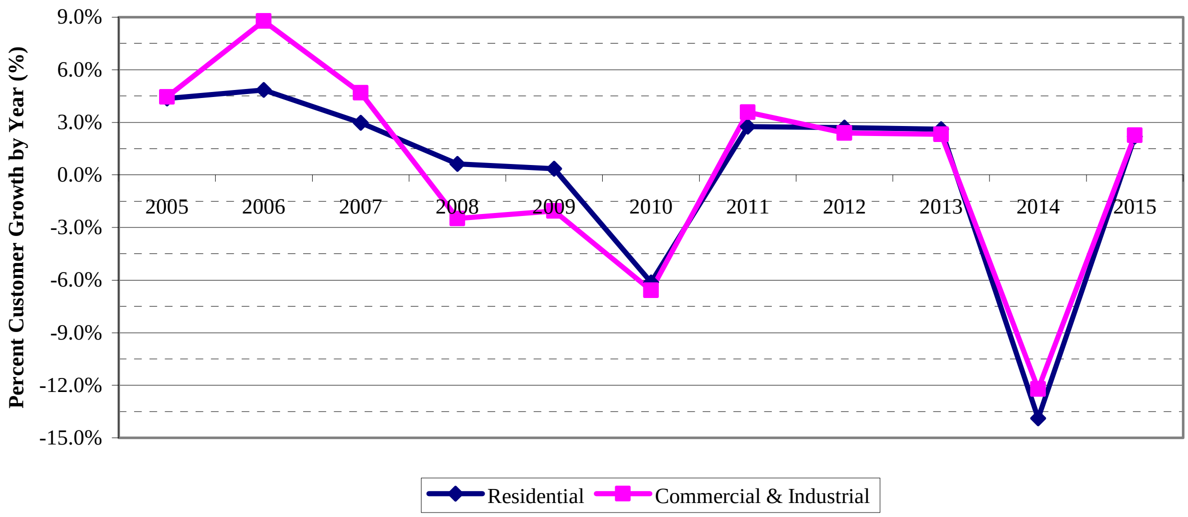
**Peak Demand and Energy Forecast**

SEC forecasts that in 2020, its summer net firm peak demand will increase to 4,072 and it will generate 18,691 GWh.

SEC's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. Figure 53 shows the historic and projected rates of customer growth for SEC for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

Because SEC's members serve significant portions of the less urbanized areas of the state which are located adjacent to metropolitan areas, SEC's customer growth rates are impacted by suburban growth around these urban centers. The growth rates shown in Figure 53 illustrate this fluctuation. The drop in customers in 2014 is due to the Lee County Electric Cooperative load no longer being served by SEC beginning January 1, 2014.

**Figure 53. SEC: Customer Growth Rates**



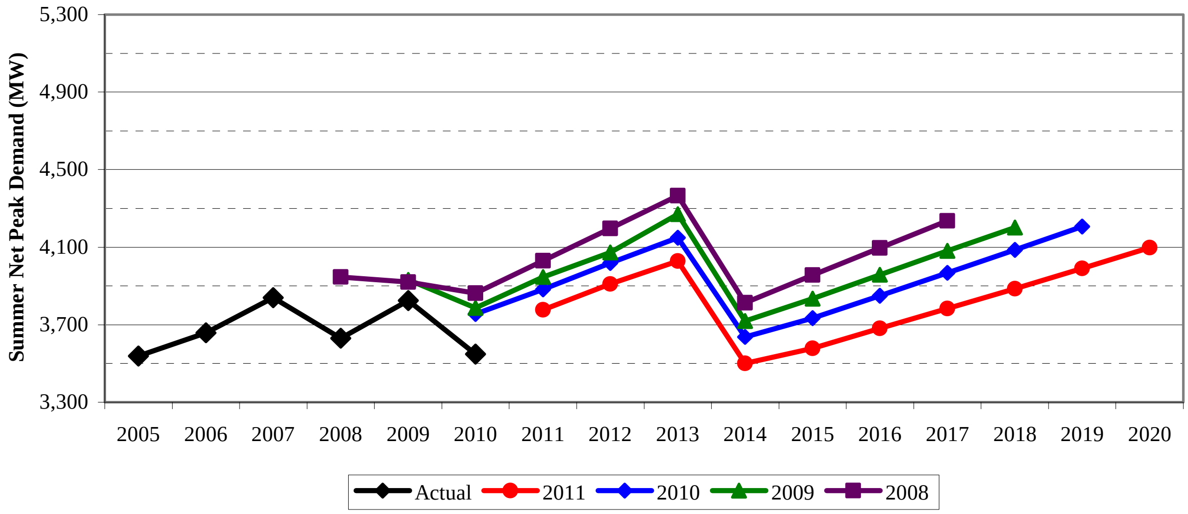

The three graphs in Figure 54 show the actual values for SEC's summer and winter peak demand, and its NEL from 2005 through 2010. In addition, the forecasts for each of these quantities is shown for the 2008, 2009, and 2010 plan years, as well as that of the current plan year.

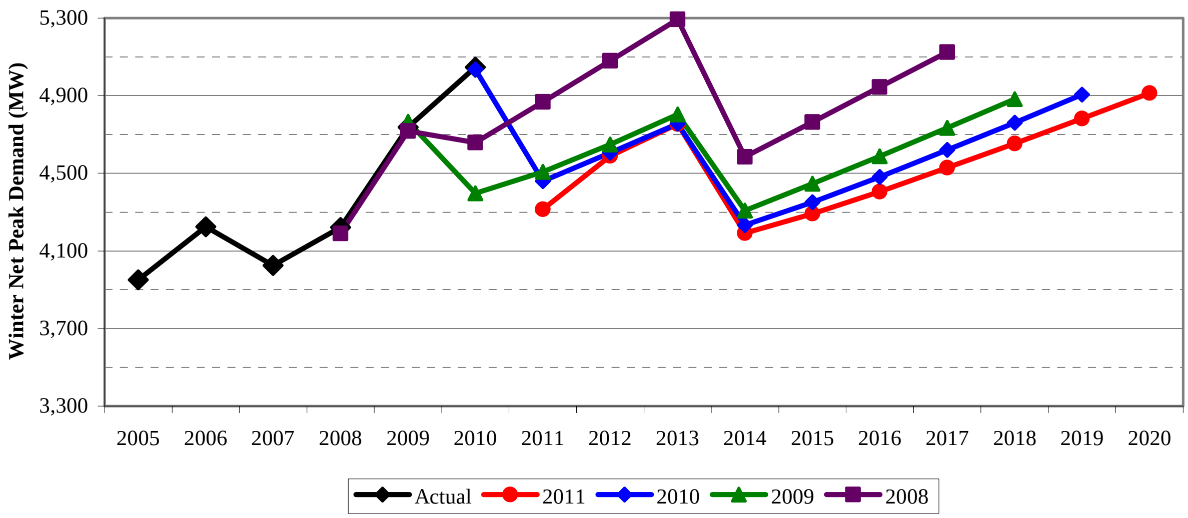
Both of the seasonal peak demand forecasts, as well as the NEL forecast, are quite consistent with previous forecasts. All three forecasts have been lowered each year, and the latest forecast in 2011 is the lowest.

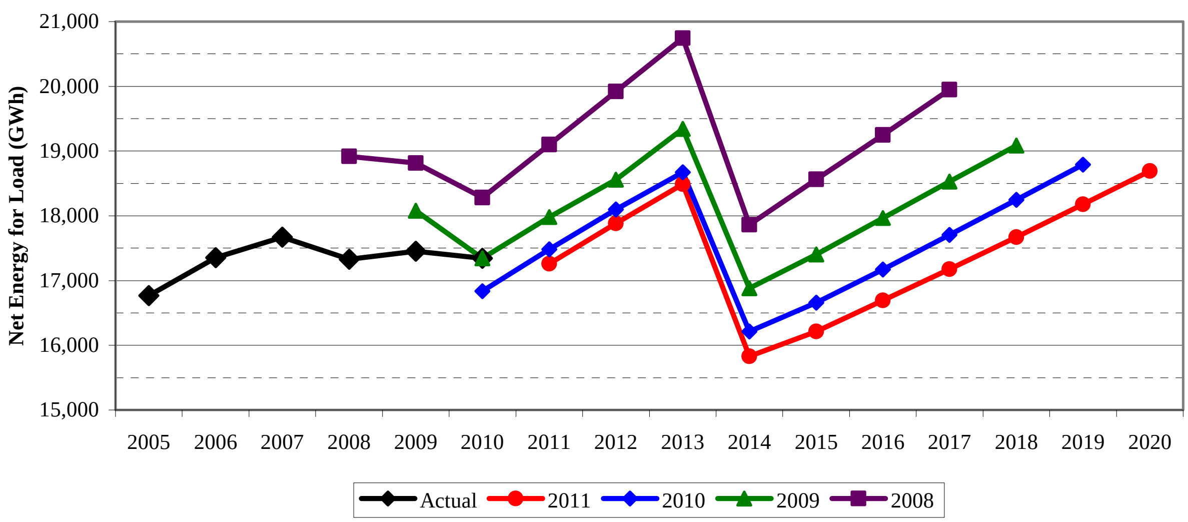
All of the forecasts project the demand and NEL to increase steadily with the exception of the year 2014. As discussed previously, beginning in 2014 SEC will no longer serve the load of Lee County. The elimination of Lee County's load causes the forecasts for demand and energy to decrease significantly.

Analysis of SEC's historical forecast accuracy for total retail energy sales from 2006 through 2010 shows that the average forecast error is 0.08 percent. This value indicates that SEC tends to over-forecast its retail energy sales by 0.08 percent. When compared to the overall average forecast error of 2.44 percent for all the TYSP utilities, SEC's error rate is much lower and is, in fact, the lowest of all the TYSP utilities.

**Figure 54. SEC: Demand & Energy Forecast**



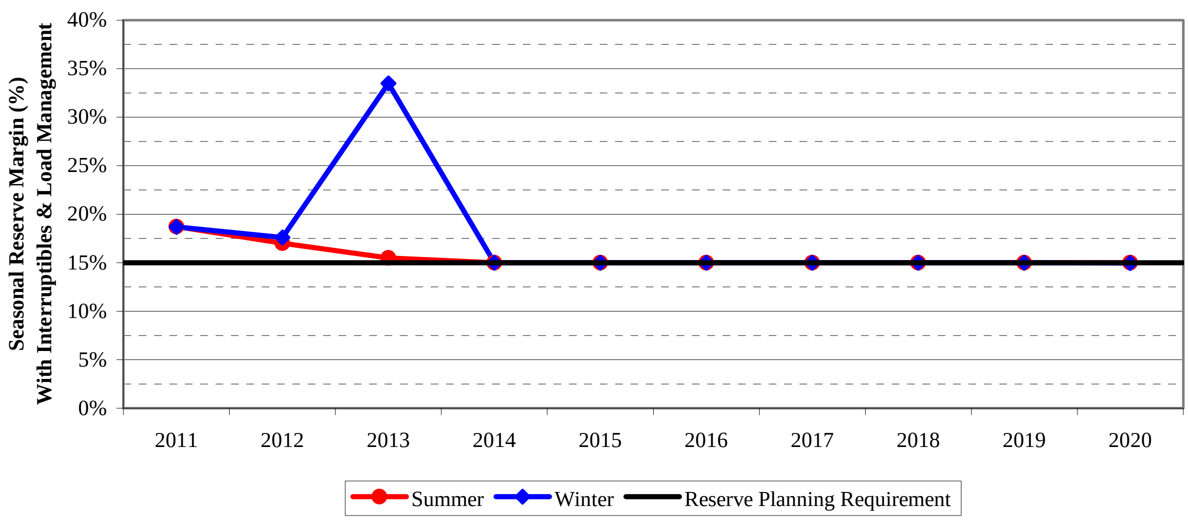
## Demand-Side Management

Because SEC is a generation and transmission rural electric cooperative that serves only wholesale customers, SEC cannot offer conservation or DSM programs directly to retail customers. However, SEC promotes member involvement in DSM through its wholesale rate signals and two specific management programs: 1) a coordinated load management program; and 2) a load management distributed generation program. Also, SEC's member utilities offer DSM programs directly to their respective retail customers.

## Reliability Criteria

SEC maintains the FRCC minimum 15 percent planning reserve margin. Figure 55 illustrates SEC's forecasted reserve margin over the ten-year planning horizon for the summer and winter seasons. As the figure shows, SEC expects to meet the 15 percent minimum level of reserve through the horizon, with an excess of winter season reserve occurring in 2013. The reason for this spike is that SEC has executed two purchased power contracts with PEF for 2013, as well as other purchased power in that year. Because some of these contracts overlap in 2013, there is a spike in the reserve for that year only.

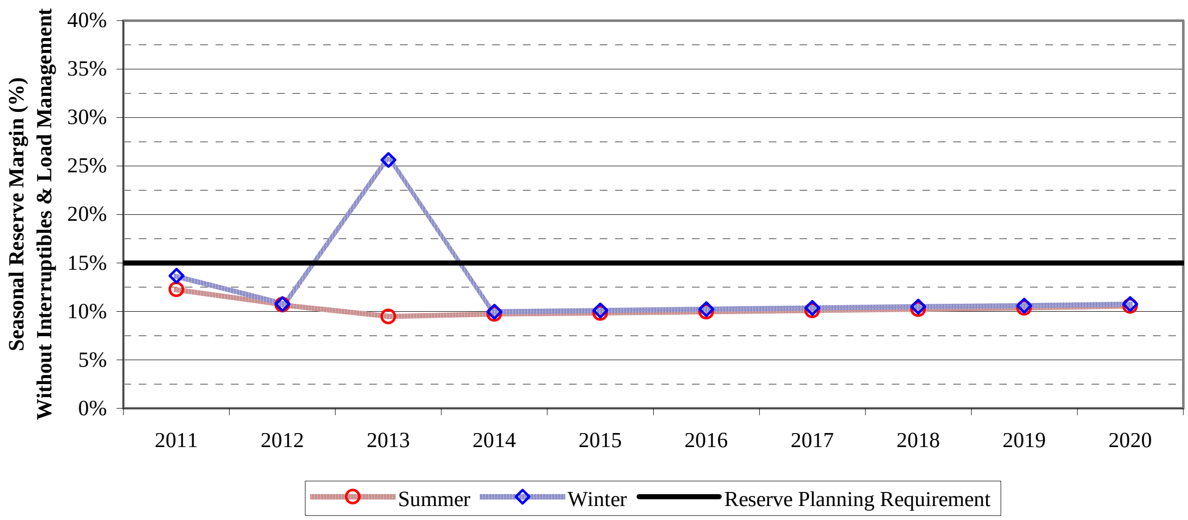
**Figure 55. SEC: Reserve Margin Projections**




Source: SEC 2011 TYSP

Because SEC does offer load management programs, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in Figure 56. As the figure shows, SEC's generation-only reserve is projected to remain at approximately 10 percent.

**Figure 56. SEC: Generation-Only Reserve Margin Projections**

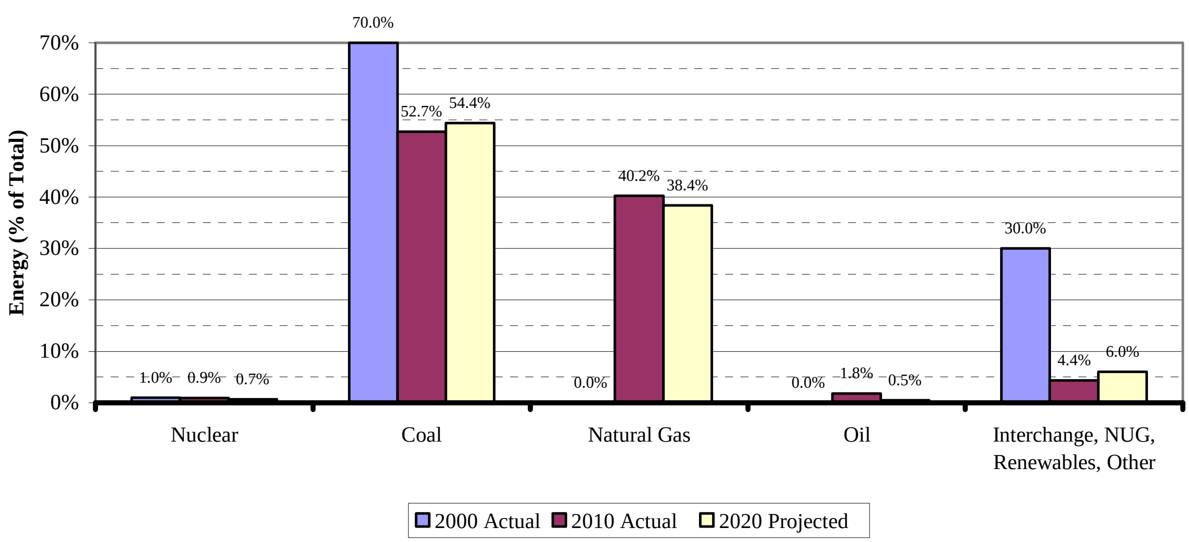



Source: SEC 2011 TYSP

## Fuel Diversity

Figure 57 displays the composition of SEC's system in terms of energy generated. As the figure shows, the amount of energy generated by coal units decreased in the years since 2000, and will increase slightly over the next ten years. SEC did not have any generation from natural gas in 2000, but now a significant portion of its generation comes from natural gas units. Another significant change since 2000 is the drop in purchased power, from 30 percent to just over 4 percent last year. The overall generation mix is projected to remain approximately the same over the planning horizon.

**Figure 57. SEC: Energy Generation by Fuel Type (Percent of Total)**




Source: SEC 2001 and 2011 TYSP

## Generation Additions

Table 20 shows in detail the expansion plan in SEC's 2011 TYSP. One CT unit is planned to become operational in 2018, two CTs in 2019, and three CTs in 2020. In addition, SEC is planning to have two new CC units coming in-service in 2020. Two of the CTs and both of the CCs are appearing in SEC's TYSP for the first time in 2011.

**Table 20. SEC: Generation Additions by Technology Type**

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Combustion Turbine Unit Additions** | | | | |
| Future CT 1 | 158 | n/a | n/a | 12 / 2018 |
| Future CT 2 | 158 | n/a | n/a | 12 / 2019 |
| Future CT 3 | 158 | n/a | n/a | 12 / 2019 |
| Future CT 4 | 158 | n/a | n/a | 12 / 2020 |
| Future CT 5 | 158 | n/a | n/a | 12 / 2020 |
| Future CT 6 | 158 | n/a | n/a | 12 / 2020 |
| **Combined Cycle Unit Additions** | | | | |
| Future CC 1 | 196 | None yet | None yet | 12 / 2020 |
| Future CC 1 | 196 | None yet | None yet | 12 / 2020 |

Source: SEC TYSP

## *CITY OF TALLAHASSEE (TAL)*

The City of Tallahassee (TAL) owns, operates, and maintains it electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City.

Tallahassee had a total summer net firm generating capacity of 601 MW and generated 2,931 GWh in 2010, which makes up 1.2 percent of the total NEL for the State of Florida.

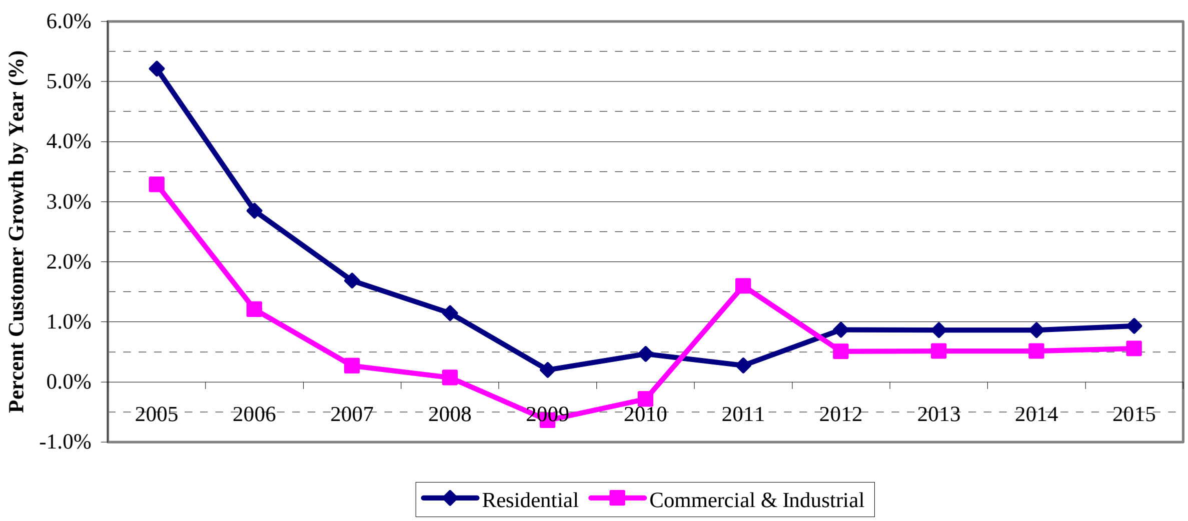
**Peak Demand and Energy Forecast**

Tallahassee forecasts that in 2020, its summer net firm peak demand will be 529 MW, and it will generate 2,711 GWh.

Tallahassee's peak demand and energy forecasts include projections of customer growth, seasonal peak demand, and NEL. Figure 58 shows the historic and projected rates of customer growth for TAL for the years 2005 through 2015. The values for 2005 through 2010 are actual values, and those for 2011 through 2015 are projected.

Figure 58 shows that Tallahassee has lost customers in four of the previous five years. The rate of growth over the next five years is projected to remain at less than one percent.

**Figure 58. TAL: Customer Growth Rates**



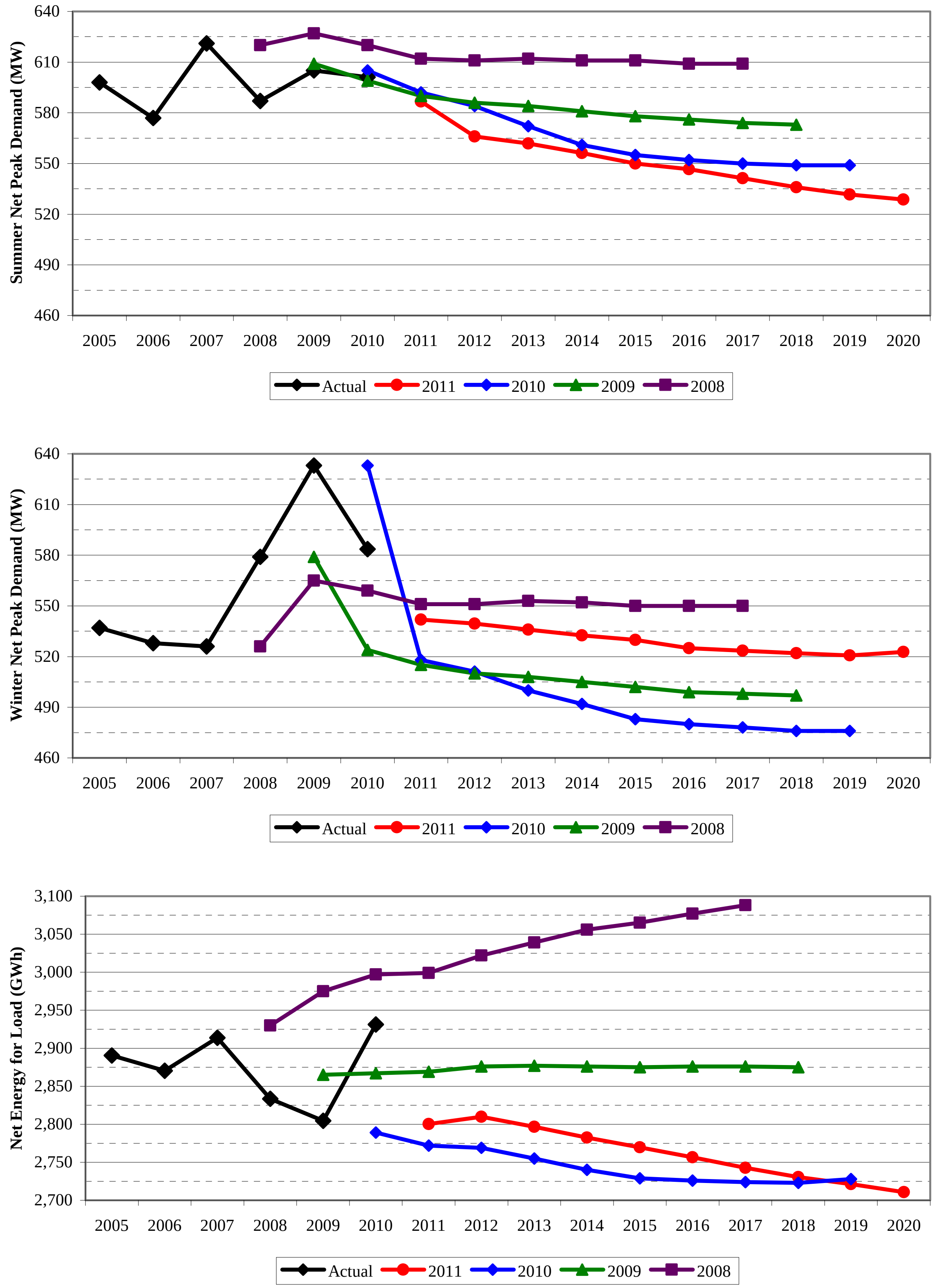
The three graphs in Figure 59 show the actual values for TAL's summer and winter peak demand, and its NEL from 2005 through 2010. The figure also shows the forecasts for each of these quantities for the 2008, 2009, 2010, and 2011 plan years.

The current summer peak demand forecast is lower than any previous forecast shown in the chart. The current winter peak demand forecast is higher than the two previous forecasts, but lower than the 2008 projection. Both seasonal demand forecasts, however, are projecting a decreasing demand over the ten-year planning horizon.

The current NEL forecast is higher than the 2010 projection, but lower than both the 2008 and the 2009 forecasts. Like the peak demand forecasts, the NEL forecast is projecting a decreasing load for the entire planning horizon.

Analysis of the historical forecast accuracy for Tallahassee's total retail energy sales from 2006 through 2010 results in an average forecast error of 2.5 percent. This figure denotes Tallahassee's tendency to slightly over-forecast its retail energy sales by 2.5 percent, but it compares well to the overall average forecast error of 2.44 percent for all the TYSP utilities.

**Figure 59. TAL: Demand & Energy Forecast**



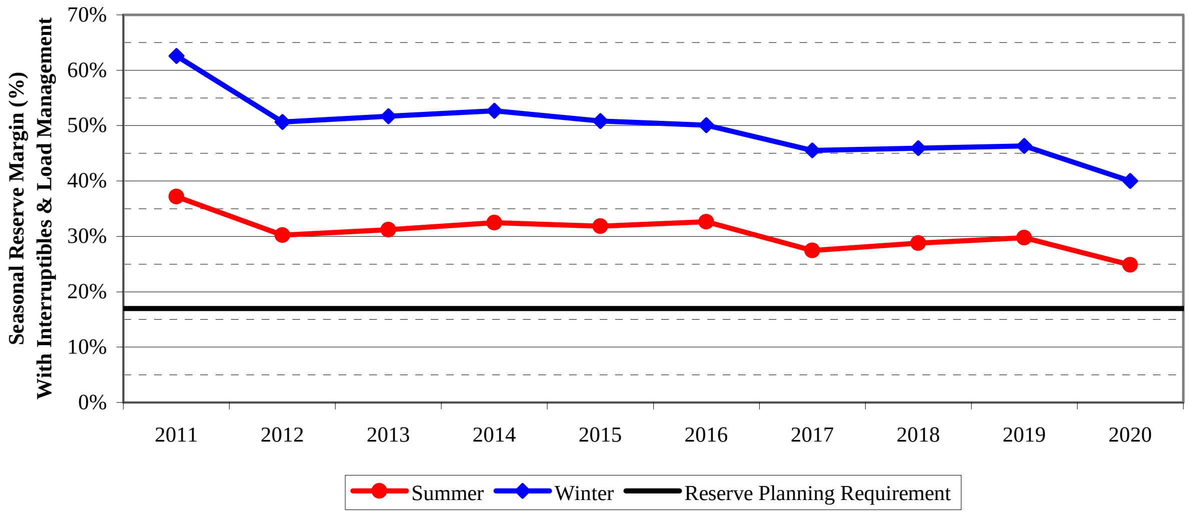
## Demand-Side Management

Although Tallahassee does not fall under the requirements of FEECA, and therefore is not subject to Commission-set DSM goals, it does have Energy Efficiency and Demand-Side Management Programs, for both residential and commercial customers. TAL does administer active load management or interruptible programs which increase the overall reserve margin.

## Reliability Criteria

Tallahassee is affiliated with the FRCC and therefore maintains a 15 percent reserve margin. Figure 60 shows that, over the entire ten-year planning horizon, Tallahassee has sufficient reserve capacity.

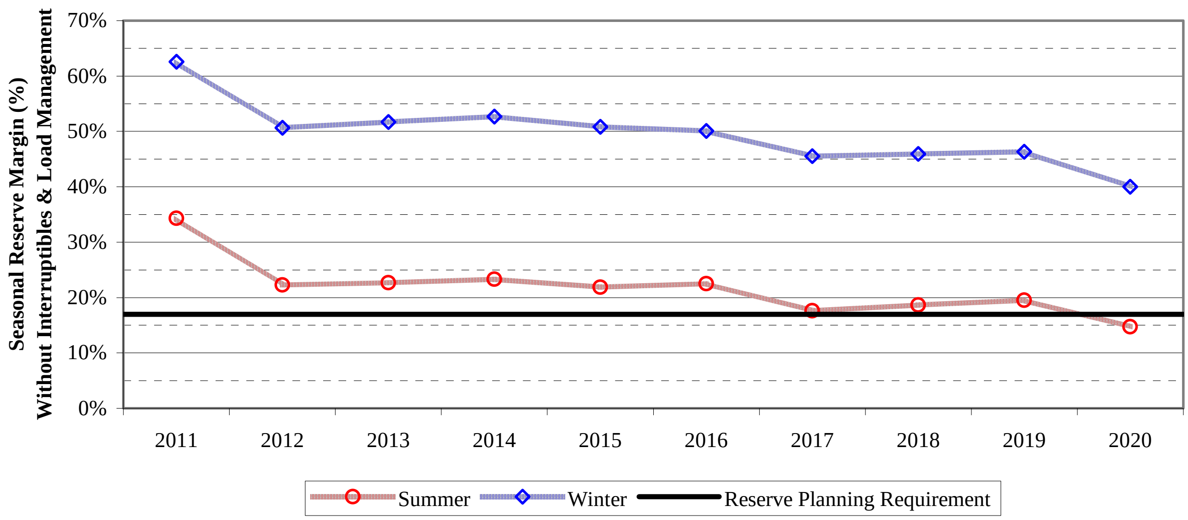
**Figure 60. TAL: Reserve Margin Projections**




Source: TAL 2011 TYSP

Because TAL does have active load management and interruptible load programs in place, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in Figure 61. The figure shows that TAL's level of reserve margin from supply-side resources is sufficient.

**Figure 61. TAL: Generation-Only Reserve Margin Projections**

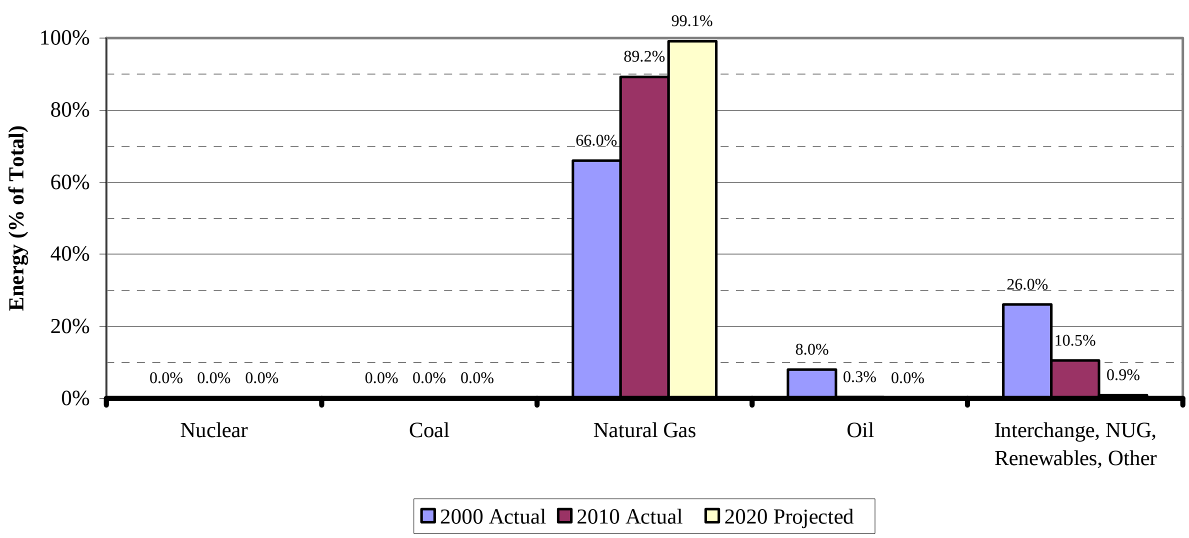



Source: TAL 2011 TYSP

## Fuel Diversity

Figure 62 displays the composition of Tallahassee's system in terms of energy generated. The figure shows clearly that Tallahassee generates the vast majority of its energy from natural gas sources, and by 2020 natural gas units will produce very nearly 100 percent of the total energy generated. Purchased power is the only other source of significance, although a small amount of renewable energy is generated. Other than purchasing less energy over the planning horizon, Tallahassee's energy generation is not expected to change appreciably.

**Figure 62. TAL: Energy Generation by Fuel Type (Percent of Total)**




Source: TAL 2001 and 2011 TYSP

## Generation Additions

Tallahassee has only one new generating unit in its 2011 TYSP. Hopkins unit 5, a 46 MW CT, is planned to be operational in 2020. This unit is appearing in Tallahassee's TYSP for the first time in 2011. Table 21 displays this information.

**Table 21. TAL: Generation Additions by Technology Type**

| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Combustion Turbine Unit Additions** | | | | |
| Hopkins CT 5 | 46 | n/a | n/a | 5/2020 |

Source: TAL 2011 TYSP