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<table>
<thead>
<tr>
<th>Table of Contents</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0 Purpose... ............................................................</td>
<td>4</td>
</tr>
<tr>
<td>2.0 Terms and Definitions ..........................................</td>
<td>4</td>
</tr>
<tr>
<td>3.0 Responsibilities ....................................................</td>
<td>4</td>
</tr>
<tr>
<td>4.0 Executive Summary ...................................................</td>
<td>5</td>
</tr>
<tr>
<td>5.0 FRCC Reserve Margin Review .....................................</td>
<td>7</td>
</tr>
<tr>
<td>6.0 FRCC Resource Adequacy Criteria Review ..................</td>
<td>10</td>
</tr>
<tr>
<td>7.0 FRCC Load Forecast Evaluation ...............................</td>
<td>19</td>
</tr>
<tr>
<td>8.0 FRCC Transmission ...................................................</td>
<td>27</td>
</tr>
<tr>
<td>9.0 FRCC Fuel Reliability .............................................</td>
<td>28</td>
</tr>
<tr>
<td>10.0 FRCC Renewables Energy Resources .........................</td>
<td>30</td>
</tr>
<tr>
<td>11.0 References ..........................................................</td>
<td>32</td>
</tr>
<tr>
<td>12.0 Review and Modification History ...........................</td>
<td>32</td>
</tr>
<tr>
<td>13.0 Disclaimer ..........................................................</td>
<td>32</td>
</tr>
</tbody>
</table>
1.0 Purpose

A key responsibility of the Florida Reliability Coordinating Council (FRCC) is to annually assess the reliability of the Bulk Power System in the Region, and to ensure resource adequacy as required by the Florida Public Service Commission (FPSC) as well as a requirement for compliance with FRCC Standards and North American Electric Reliability Corporation (NERC) Reliability Standards. NERC is the Electric Reliability Organization (ERO) of the United States.

As part of this annual assessment, the FRCC aggregates and reviews forecasted load and resource data reflecting expected conditions over the next ten years. The FRCC receives data annually from its members to develop the Regional Load & Resource Plan (RLRP). Based on the information contained in the RLRP, this Load & Resource Reliability Assessment Report (Reliability Assessment Report) is developed and submitted to the FPSC along with the RLRP.

The Reliability Assessment Report evaluates the projected reliability for peninsular Florida east of the Apalachicola River by analyzing projections of Reserve Margins, Loss of Load Probability (LOLP), Availability Factors (AF), and Forced Outage Rates (FOR). In addition, this report incorporates various reliability-based aspects of work performed by the Load Forecast Working Group (LFWG), Transmission Working Group (TWG), Fuel Reliability Working Group (FRWG), and examines renewable energy use in Florida.

2.0 Terms and Definitions

2.1 Terms are defined within the document.

3.0 Responsibilities

3.1 Resource Working Group (RWG)

The RWG is responsible for reviewing document.

3.2 Load Forecast Working Group (LFWG)

The LFWG is responsible for reviewing document.

3.3 Fuel Reliability Working Group (FRWG)

The FRWG is responsible for reviewing document.

3.4 Transmission Working Group (TWG)

The TWG is responsible for reviewing document.

3.5 Planning Committee (PC)

The PC is responsible for the final approval of this document.

Classification: Public
4.0 Executive Summary

In summary, the findings of the 2016 Reliability Assessment Report of the FRCC Region are:

- Peninsular Florida’s electric service is projected to be reliable from a resource adequacy perspective throughout the ten-year planning horizon.
  - Reserve margins for the FRCC Region for the summer and winter peak hours are projected to exceed 20% for each year in the ten-year period which is above the FRCC’s minimum Reserve Margin Planning Criterion of 15%.
  - Loss of Load Probability (LOLP) analyses results are projected to meet an LOLP level of 0.1 days per year which is commonly used in the industry as a reliability criterion.
  - The Reserve Margin and LOLP results are supplemented with projected low Forced Outage Rates (FOR) and high Availability Factors (AF) which are largely due to the utilities’ modernization efforts.
  - These analysis results support a conclusion that the peninsular Florida system is projected to continue to be reliable throughout the ten-year period addressed in this document.
  - Because the peninsular Florida system was, several years ago, projected to be increasingly dependent upon Demand Side Management (DSM) to meet its Reserve Margin criterion, the FRCC and certain utilities continue to examine system reliability utilizing a generation-only Reserve Margin perspective.

- The load forecast is both reasonable and sound while reflecting moderate growth over ten years, but assumes lower load growth than in prior years.
  - The expected average annual growth rate for Net Energy for Load (NEL) is 0.8% per year compared to 1.1% in the previous forecast.
  - Firm summer peak demand is expected to grow by 1.1% per year compared to 1.5% in the previous forecast.
  - Firm winter peak demand is expected to grow by 1.0% per year compared to 0.9% in the previous forecast.

- A net total (including unit retirements) of approximately 8,300 MW (summer) of additional utility-owned generation resources are planned for the FRCC Region.
  - Approximately 12,100 MW of new non-renewable generation are planned for the FRCC Region with 9,700 MW being combined cycle capacity and 2,400 MW being combustion turbine capacity. In addition, approximately 1,100 MW of nameplate solar capacity is planned.
  - Approximately 4,300 MW of plant retirements are expected from coal plant capacity and older, less efficient steam and combustion turbine capacity and more than 500 MW in unit uprates or other capacity adjustments.
- Natural Gas is expected to remain the primary fuel source for the region and the majority of proposed new generators within the FRCC Region are expected to use natural gas as their primary fuel.

  - Natural gas is projected to provide approximately 65% of the electrical energy (GWh) in peninsular Florida in the coming ten years. The existing pipeline capacity within the Region supports the current generating capacity needs of the Region.

  - In the event of a short term failure of key elements of natural gas delivery infrastructure, there is sufficient back up fuel capability to meet projected demand. It should be noted that additional coordination may be required in the event of a long-term failure of key elements of natural gas delivery infrastructure.

  - Significant proposed gas pipeline projects (Sabal Trail and Florida Southeast Connection) are expected to provide 0.83 Bcf of incremental gas transportation capacity to peninsular Florida in May 2017 and increasing to 1.1 Bcf by 2021. Completion of these projects will enhance fuel transportation reliability by increasing supply and delivery diversity for the FRCC Region. This capacity will also help the FRCC Region meet the increasing gas generation requirements being constructed over the next 10 years.
5.0 FRCC Reserve Margin Review

The FRCC has a reliability criterion of a 15% minimum Regional Total Reserve Margin based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and DSM resources on an annual basis to ensure that the Regional Reserve Margin requirement is projected to be satisfied. The three Investor Owned Utilities, Florida Power & Light Company (FPL), Duke Energy Florida (DEF), and Tampa Electric Company (TEC), are utilizing, along with other reliability criteria, a 20% minimum Total Reserve Margin planning criterion consistent with a voluntary stipulation agreed to by the FPSC\(^1\). Other utilities employ a 15% to 18% minimum Total Reserve Margin planning criterion.

If projections had shown a forecasted peak period for which the Regional Total Reserve Margin requirement would not be met, such a projection would be researched and reflected in the annual Reliability Assessment Report. Currently, there are no such projections for the next ten years.

\(^1\) Docket No. 981890-EU Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida, Order No. PSC-99-2507-S-EU, issued December 22, 1999 (http://www.psc.state.fl.us/library/Orders/99/15628-99.pdf)
**Figure 1** below shows that the projected summer Total Reserve Margins from the 2016 Regional Load & Resource Plan continue to be above the FRCC’s minimum 15% Total Reserve Margin requirement. In fact, the 2016 projected summer Total Reserve Margins exceed 20% for every year in the ten-year forecast period.

(Note that information contained in this Figure, and in subsequent Figures and Tables, is consistent with information presented in the individual utilities’ 2016 Site Plans. These Site Plans present information from the utilities’ 2015 and early 2016 resource planning work.)

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**Figure 1**

*Trends in Projected Summer Total Reserve Margins*

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In a similar manner, Figure 2 below shows the projected winter Total Reserve Margins from the 2016 Regional Load & Resource Plan. The 2016 projected winter Total Reserve Margins are also over 20% for every year in the ten-year forecast period. Primary drivers of the higher winter reserve margins are: (i) colder ambient air temperatures in the winter result in more capacity (MW) output from many generators when compared to summer, and (ii) the forecast of winter peak demand is lower in the current forecast compared to the prior forecast.

Figure 2

Trends in Projected Winter Total Reserve Margins

3 The winter season spans from the 4th quarter of one year through the 1st quarter of the next year. For example, the year 16/17 refers to the winter season spanning from the 4th quarter of 2016 through the 1st quarter of 2017.
6.0 FRCC Resource Adequacy Criteria Review

Introduction

Loss-of-Load-Probability (LOLP) projections are developed in analyses that are conducted every other year. In addition, projections of generator Forced Outage Rates (FOR) and Availability Factors (AF) are developed annually. The results of these analyses are utilized, in combination with the above described Total Reserve Margin Review, to determine if the planned resources for the FRCC Region are adequate to meet FRCC, FPSC, and NERC requirements. Further, other considerations that can affect system reliability are also considered and evaluated.

LOLP Analysis

The FRCC has historically used an LOLP analysis to establish the adequacy of reserve levels for peninsular Florida. The LOLP analysis uses projected system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to meet forecasted loads. The purpose is to verify that the projected LOLP for the system does not exceed the criterion of a maximum LOLP of 0.1 day in a given year. In addition to maintaining this LOLP resource level, the FRCC established an additional Regional Reserve Margin Planning Criterion (also known as a Resource Adequacy Criteria) of a minimum 15% Total Reserve Margin for both summer and winter versus firm load.

Until recently, the Resource Working Group (RWG) performed periodic LOLP studies every 3 to 5 years. However, NERC’s Probabilistic Assessment requires analyses of Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) every other year. Therefore, the RWG is now conducting LOLP analyses biennially, in parallel with the EUE and LOLH analyses. All three analyses utilize the same data.

The previous LOLP analysis was conducted in 2014. At that time, “base” LOLP projections were obtained for peninsular Florida for the years 2014 through 2018 using updated assumptions and forecasts that correspond with the Florida utilities’ 2014 Ten Year Site Plans (TYSP). Beyond the base or “reference” case values for LOLP, projected LOLP values for a variety of extreme scenarios were considered, including: (i) no availability of firm imports, (ii) no availability of load management/demand response (DR) types of DSM programs, and (iii) a high load case.

The same analysis approach, using base and scenario cases, was used in 2016 using updated 2016 assumptions and forecasts that matched those from Florida utilities’ 2016 TYSPs. The analysis period addressed the years 2016 through 2020 and accounted for all of the approximately 300 generating units in the FRCC Region. Results indicate that Florida peninsular system is projected to be reliable from an LOLP perspective through 2020. In other words, the peninsular Florida electric system is projected to not exceed the planning LOLP criterion of a maximum of 0.1 days per year with all transmission facilities in service for the reference case and the scenario cases. The projected LOLP values are shown in Table 1 below.

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4 The NERC Probabilistic Assessment may become an annual process in the near future. If this were to occur, FRCC would begin performing LOLP analyses annually as well.
The FRCC is scheduled to conduct an updated LOLP analysis in 2018 at the same time that new EUE and LOLH analyses are conducted.

**Forced Outage Rates (FOR) and Availability Factors (AF)**

Generating unit reliability is a primary driver of LOLP results. For a number of years, the RWG has tracked and monitored capacity (MW)-weighted Forced Outage Rate (FOR) and Availability Factor (AF) measures for individual utility systems and the FRCC Region as a whole. This assessment was again conducted as part of the 2016 Reliability Assessment. The individual utility system information is aggregated to develop MW-weighted FRCC Regional FOR and AF values. Actual and forecasted FOR and AF values are then compared to historic values. Projections of these annual measures for individual utilities and the region as a whole, plus projected changes from year-to-year, are implicit indicators of system reliability from an LOLP perspective.

In the current analysis, both yearly capacity-weighted FOR and AF projected values for each utility system were calculated. The calculations were based on each utility's latest planning assumptions as presented in each utility's 2016 Site Plan. These 2016 projections for FOR and AF values were compared to the values projected in 2013, 2014, and 2015.

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5 The 2016 LOLP results are based on: (i) a load variation model and (ii) a manual approach to generator maintenance inputs which typically results in higher LOLP values than would result if using an automatic maintenance approach.

Classification: Public
As seen in Figure 3 below, the 2016 projection of FOR values remain generally in-line with projected values from the last several years. The current projected FOR values are relatively flat and in a relatively narrow range. This trend is also consistent with projections from the prior years. The projected flat FOR values are also consistent with the projected low LOLP base case values from the 2016 LOLP analyses presented earlier in Table 1. This consistency in FOR projections further indicates that the peninsular Florida system is projected to remain resource adequate and maintain its reliability from 2016 through 2025.

**Figure 3**
*Trends in Projected Forced Outage Rates (FOR)*
Though unit AF is not an input to LOLP calculations, it is often used as an indicator that generally correlates well with reliability data. Figure 4 below shows that 2016 projections of MW-weighted AF throughout the ten-year period are in line with AF projections from recent years. The projections from resource planning work conducted in these four years remain consistent in a narrow range from approximately 88% to 91% with a general trend of increasing AF values.

![Comparison of MW-Weighted AF for FRCC: 2013, 2014, 2015, and 2016 Projections](image)

**Figure 4**

*Trends in Projected Availability Factors (AF)*

The results of the AF analyses, combined with the results of the FOR analyses depicted in Figure 3, the very low projected LOLP base case results for 2016 – 2020, and the projections of Total Reserve Margins for all years that are above the FRCC’s minimum Total Reserve Margin Planning Criterion of 15% (as presented in the 2016 Load & Resource Plan document and presented in the previous section in Figure 1 and Figure 2), support a conclusion that the peninsular Florida system is projected to continue to be reliable throughout the ten-year period addressed in this document.

Based on these analyses, the RWG recommends that the current 15% Total Reserve Margin Planning Criteria be maintained.
Resource Adequacy Review Process

In addition to the NERC Probabilistic Assessment work, other resource adequacy work that is conducted can be summarized as follows:

Examination of potential new statistics for evaluating system reliability

In 2012, the RWG also began to examine an additional aspect of the peninsular system that could have implications for the reliability of the system. This aspect is the extent to which the system’s projected Total Reserve Margin values rely upon DSM to meet and maintain the FRCC’s 15% Total Reserve Margin Planning Criterion. In 2014, FPL adopted a minimum 10% generation-only reserve margin (GRM) as a third reliability criterion in its Integrated Resource Planning (IRP) process. The GRM criterion is now in use in all of FPL’s IRP analyses and FPL’s objective is to achieve a minimum 10% GRM in practice annually beginning in the year 2019. The GRM criterion supplements FPL’s other two reliability criterion, a 20% minimum total reserve margin for summer and winter and a maximum LOLP of 0.1 day per year. FPL’s GRM criterion is similar in concept to TEC’s supply-side reserve margin reliability criterion that TEC has used in its IRP process for more than a decade. Both of these criteria are essentially designed to ensure that there is an adequate generation component as the utilities meet their 20% total reserve margin criterion.

In order to examine the extent to which the peninsular Florida system is dependent upon DSM, and whether the system is projected to become more dependent upon DSM over time, a projection of annual “generation-only” Reserve Margin values was first developed based on information presented in the utilities’ 2012 Site Plans and the projected generation-only Reserve Margin for peninsular Florida has been analyzed by the RWG in each subsequent year. The generation-only Reserve Margin analysis for peninsular Florida was conducted again this year by aggregating the utilities’ 2016 TYSP projections in which incremental and cumulative load management, and incremental utility program energy conservation/energy efficiency and other demand reduction contributions, are excluded. The resulting generation-only Reserve Margin projection, presented in Figure 5 below, shows peninsular Florida’s projected future Reserve Margins when considering only generating unit contributions.

For purposes of calculating projected 'generation-only reserve margin' values, the following formula was used:
(total capacity - load forecast) / load forecast, in which the following DSM components have been removed from the calculation: existing load management capability, projected new incremental load management capability, and projected new energy efficiency/energy conservation utility program additions.

Classification: Public
As shown in *Figure 5*, the generation-only Reserve Margin values for peninsular Florida are projected to decrease through 2018 to approximately 13%, but then to remain relatively steady at approximately 15% for the remaining years of the projection. This indicates that the previously projected trend of steadily increasing dependence on DSM for maintaining reliability of the peninsular Florida system is now anticipated to stop beginning in 2019. At that time, the GRM for peninsular Florida is projected to hold steady going forward (but at slightly lower levels than in 2016). The primary reasons for this change in the projection of dependence on DSM for system reliability of peninsular Florida are: (i) DSM’s diminished cost-effectiveness in Florida was appropriately reflected in lower DSM Goals being set for Florida utilities for the 2015 – 2024 time period, and (ii) FPL’s use of its 10% minimum GRM reliability criterion (recognizing that the FPL system constitutes approximately 50% of the peninsula’s projected capacity and load.)

The FRCC and individual utilities including FPL will continue to evaluate these generation-only Reserve Margin projections and their potential implications for system reliability.

**Fuel Deliverability**

The dependency on natural gas and the possibility of natural gas supply or delivery disruptions and potential impacts on the long term adequacy of FRCC resources to meet customer load has been considered in resource adequacy reviews. The FRCC has undertaken initiatives to increase coordination among natural gas pipeline operators and generators within the Region. The FRCC, through its Fuel Reliability Working Group (FRWG), provides the administrative oversight of a Regional fuel reliability forum that assesses the interdependencies of fuel availability and electric reliability.

Results of the most recent analysis indicate that risk to the reliability of the power system within the FRCC Region related to projected shorter term gas delivery disruptions can be mitigated through use of dual fuel units and increased fuel management coordination.
Peninsular Florida has become dependent on natural gas as a source of fuel for electric generation. This is expected to continue over the coming years as utilities continue to install new natural gas-fired generation to meet new load, as well as replace existing generating facilities with more efficient natural gas-fired generation. Approximately 63% of the energy delivered in Florida in 2015 was generated by natural gas. Natural gas is expected to continue to be peninsular Florida’s primary fuel generating approximately 65% of the electric energy consumed on average through the year 2025. However, the state has no native gas production and currently relies primarily on two existing interstate natural gas pipelines with limited interconnections between them, Gulfstream Natural Gas System (Gulfstream) and Florida Gas Transmission Company (FGT) for more than 90% of the supply transported into the Region. These two pipelines currently have the ability to deliver almost 4.4 billion cubic feet per day (Bcf/day). FGT’s delivery capability is approximately 3.1 Bcf/day and Gulfstream’s delivery capability is approximately 1.3 Bcf/day. More than 80% of the natural gas supply from these two pipelines is dedicated to serving electric generation needs in Florida.

In addition to the two main pipelines delivering into the state, gas is also transported into peninsular Florida via Southern Natural’s Cypress Pipeline system (Cypress). This pipeline is capable of delivering about 400 million cubic feet per day (MMcf/day) into Florida. At this time, only about 60 MMcf/day of delivery capacity on Cypress is contracted for delivery to a direct use market in Florida. The vast majority of the gas from Cypress is delivered to FGT and is contracted to flow through FGT to reach end use markets. Consequently, the majority of this capacity is not additive to the FGT delivery capacity.

In terms of ensuring the reliability of Florida’s natural gas supply, utilities have added additional “upstream pipeline transportation capacity” to access onshore production, shale gas reserves as well as natural gas storage facilities. This upstream capacity allows Florida’s utilities to diversify natural gas supply away from the Gulf of Mexico and to tap the abundant shale gas reserves in Texas, Louisiana, Oklahoma, and other states. However, efforts by utilities in managing gas transportation risks, decreasing costs, and increasing supply diversity is limited by the existing access provided by the current pipeline delivery infrastructure.

In regard to future requirements, these existing natural gas pipelines into Florida are almost fully subscribed. However, Florida’s natural gas needs are expected to increase in the coming years. To meet the high demand, the gas transportation infrastructure serving the state is expected to increase by 2017. Given that the state relies on primarily two pipeline service providers that source natural gas supplies from primarily Gulf Coast area supply sources and infrastructure, Florida will benefit from projects that increase supply flexibility, delivery diversity, and increased interconnections which includes the proposed Sabal Trail, Sabal Trail Central Florida Hub, and the Florida Southeast Connection pipeline projects that are currently moving through the Federal Energy Regulatory Commission (FERC) Certificate process. These projects will provide access to a new supply source from Transco’s Zone 4 Pool at its compressor station 85 into the FRCC Region.

Additionally, a long term interruption of any of the primary pipelines serving the state could significantly impact the adequacy of resources within the FRCC to serve customer loads during the period required to repair the affected pipeline. Therefore, increasing pipeline diversity ultimately will decrease vulnerability to unplanned outages of any gas delivery infrastructure.
Environmental Compliance

At this time, the RWG believes that current environmental requirements imposed by Federal, State, and local authorities that may impact the capability and operation of generation resources are appropriately addressed within the resource adequacy process through the individual utility resource planning processes. Several federal environmental rules were recently enacted, including MATS (Mercury and Air Toxics Standards), CSAPR (Cross-State Air Pollution Rule), CWIS (Cooling Water Intake Structures), CCR (Coal Combustion Residuals), and NESHAP/RICE (National Emission Standards for Hazardous Air Pollutants / Reciprocating Internal Combustion Engine). Specifically, the MATS rule is one of the factors that led to the retirement of several units as well as the installation of additional equipment at other existing units. The NESHAP/RICE rule will continue to affect the usage of backup generators for load control programs. Many customers who participate in utility commercial/industrial load control programs utilize such equipment. As a result of this rule, costs for these participating customers may increase and/or customers may be restricted in the use of their backup generators for load control participation. These changes have the potential to decrease the MW available under the utilities’ commercial/industrial load management programs and/or to decrease the effectiveness of this DSM resource. Any other utility-specific, or generator-specific, emission limitations and/or environmental compliance costs are presently captured by incorporating these in the production costing models used in the individual utilities’ resource planning processes.

In 2015, the U.S. EPA issued its final rules regarding the Clean Power Plan (CPP) that addresses greenhouse gas emissions for all existing power plants in the U.S. However, shortly after the EPA’s final rules were issued, the U.S. Supreme Court ordered a stay of the rules and remanded the issue back to a lower court. At the time this document is being written, this stay of the CPP is still in effect. Future FRCC Reliability Assessment Reports will account for any appropriate changes in peninsular Florida utilities’ resource plans in response to the eventual legal outcome regarding the CPP.
Future Work on Resource Adequacy

The LOLP analyses discussed earlier utilize probabilistic analysis methods to quantify the ability of the generation system resources to reliably meet expected demand, incorporating the uncertainties associated with generation reliability including unit forced outage rates, maintenance schedules, load uncertainty, and demand response capabilities that vary seasonably. It must also be recognized that overall resource adequacy must also account for considerations such as transmission constraints and fuel deliverability. The RWG reviewed these considerations along with the results of the 2016 LOLP analysis, and recognized areas that can be addressed to add more depth and detail to the resource adequacy analysis.

The FRCC will continue to conduct various studies to evaluate Regional resource adequacy including the following:

**LOLP Analysis**

- **Load Forecast Uncertainty**
  The current modeling approach assumes the most likely load forecast prevails (with the exception of scenario analyses that addresses extreme summer and winter peak load). In addition, a sensitivity analysis was performed assessing a high load case for the Region to account for load forecast uncertainty. The current modeling approach also utilizes a load variation model which provides as an input to TIGER 500 variations of the load forecast. Probabilistic forecasts are being developed based on Monte Carlo type simulations of weather and Florida population growth, and will be incorporated into future studies in the analysis of forecasted load variability.

- **Major Maintenance Schedule Variation**
  The current modeling approach uses specific planned outage schedules for near-term years as projected by member entities for their generating units.

**Analysis of Growing Dependency on DSM to Maintain System Reliability**

As previously discussed, the RWG now examines annually the extent to which peninsular Florida is projected to be dependent upon DSM, rather than generation, to maintain system reliability and the implications of that degree of dependence. This issue will continue to be examined by the RWG, and by individual utilities, in subsequent years.

**Transmission Constraints**

The current modeling approach assumes that, with all transmission facilities in service, sufficient transfer capability exists between all utility systems within the FRCC Region and SERC Reliability Corporation (SERC) with the exception of sensitivities where SERC transfer is explicitly limited or precluded. In addition, the current modeling approach assumes that each utility has the ability to import power for the loss of internal generation and that each utility has the ability to export their share of operating reserves.
7.0 FRCC Load Forecast Evaluation

2015 energy sales to peninsular Florida consumers increased 4.2% while the Net Energy for Load (NEL) increased 4.3%. In aggregate, customer growth was 1.5% in 2015, slightly lower than what had been projected. Peninsular Florida’s average per-customer consumption increased for all classes in 2015. This increase is primarily the result of weather. Florida experienced an unusually hot spring with April being the hottest month of April that Florida has experienced on record. The winter was also uncharacteristically hot in which much of Florida had to sweat through a heat wave that rewrote November’s record books. Florida’s economy continues to recover and grow, but weather played more of a factor in increased sales and average consumption than growth in the economy. Impacts of conservation and energy efficiency, including the impacts of energy efficiency building codes and appliance standards, continue to contribute to the declines in per-customer consumption. This is evident through the aggregated weather-normalized average per-customer consumption being projected to decline annually over the forecast period of 2016 to 2025.

Energy sales are projected to grow at a slower pace than previously forecasted. The ten year projected annual average growth rate for energy sales is now 0.9% compared to last year’s projection of 1.2%. Customer growth is projected to accelerate over the forecast horizon; however, it is not projected to return to pre-recession levels. The projected average annual growth rate for customers is 1.5% compared to pre-recession growth rates of over 2.5%.

The FRCC Load Forecast was thoroughly scrutinized to both account for the volatility in most macro-economic factors at the time the individual utility forecasts were developed and to assess how the member utilities are accounting for these factors in their customer, energy, and peak demand forecasts. Florida’s economic outlook, historical forecast variances, and benchmarking with recent history constituted the other elements that were analyzed in this evaluation process.

The impacts on load growth from the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 were analyzed. Most utilities incorporate these mandated energy efficiency impacts in their load forecasts. Other utilities capture these embedded efficiency trends that have been taking place historically through their econometric models.

The FRCC aggregates the individual peak demand forecast of each of its member utilities by summing these forecasts to develop the FRCC Region forecast. FRCC has pursued this avenue along the logical assumption that each utility is most familiar with its own service territory and the behavior patterns of the customer base. The load forecast evaluation process undertaken by FRCC is designed to ensure that each utility is availing itself of the best available information in terms of data, to understand which forecasting models are used, and, to a certain degree, seek consistency of assumptions across all utilities. FRCC’s Load Forecasting Working Group (LFWG) reviewed in detail each utility’s forecast methodology, input assumptions and sources, and output of forecast results. Sanity checks were performed comparing the historical past with the projected load growth, use per customer, weather-normalized assumptions, and load factors.

Although a significant amount of advancement has been achieved in the science of forecasting and statistical modeling, there still remains an amount of risk or forecast variance associated with the uncertainties embedded in the primary factors that determine the demand for electricity. The uncertainties that are most noticeable are

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departures from historical weather patterns, recent population growth, performance of the local and national economy, size of homes and number of homes being built, inflation, interest rates, price of electricity, changing electric end use technology, appliance efficiency standards, and changes in consumption patterns. In the short-run, weather deviations from the normal is the most important factor. However, population growth, economic performance, price of electricity, changing technology, changing consumption patterns, and efficiency building codes and standards also play crucial roles in explaining the growth in demand for electricity over the long-run. The load forecast should provide an unbiased estimate of the future load after accounting for these uncontrollable factors. The projections of load should not consistently under- or over-forecast the actual loads. Additionally, it is desirable that the forecasting processes used by the member utilities of FRCC exhibit continuous improvement that can be measured by the size of the weather-normalized forecast variance.

Methodology

The FRCC’s evaluation process of each individual member’s load forecast and forecasting methodologies is described in the following sections.

Models

The LFWG reviews and technically assesses the properties and theoretical specifications of the forecasting models utilized to develop the individual utility’s forecast without recommending or endorsing a particular type of model. There is an evident preference for econometric models over end-use modeling by utilities in the state of Florida. However, more and more utilities are finding it advantageous to combine econometric models with other types of forecasting models (which were basically hybrids of end-use and econometric models). The ultimate measure of how well a model is performing is the size of the weather-normalized forecast variance.

The LFWG was attentive as to the forecasting results, and cannot categorically endorse one type of model over the other based upon the results obtained. The LFWG does not consider it prudent to standardize the types of forecasting models to be used in Florida because each service territory is different and certain types of models seem to yield better results under specific conditions. The FRCC’s review ensures that all employed models portray good statistical properties with correct specifications between the key factors affecting the level of demand for electricity and the resulting load forecast. It is customary that all utilities update and refine their models with each additional year of actual data, which ensures that the most recent correlations and associations embedded in the data are captured and that the models are calibrated accordingly. Furthermore, this ensures that the starting point of each forecast series is adjusted to the latest historical value for load or customer growth.

Inputs

The input assumptions that feed the forecasting models used to project load, as well as the sources of these inputs, were assessed. The primary inputs that were examined included: Florida population and customers, the price of electricity, normal weather assumptions, an economic outlook for income and employment levels and saturations/efficiencies of electrical appliances in those models that combine end-use technology with econometric modeling. The source data for Florida’s population was the Florida Legislature’s Office of Economic and Demographic Research (EDR), which works in
conjunction with the *Bureau of Economic and Business Research from the University of Florida*\(^\text{10}\), and from *Moody's Economy.com*\(^\text{11}\) and *Global Insight*\(^\text{12}\), all reputable forecasting organizations. The price of electricity was derived internally by each utility and consisted of base rates and all “pass-through” clauses filed with the FPSC. The National Oceanographic and Atmospheric Administration (NOAA) and utility-owned weather stations provided historical weather used in model estimation and calibration.

Because each utility’s service territory has its own characteristics, different time horizons were used to determine the values for normal weather that best fits their territory. As such, some utilities employed the average weather over the last 20 years, others the last 10 or 30 years, and some used longer time periods to define what was considered as “normal” weather. There is no prescribed correct measure of “normal” weather and utilities will rely on the definition that best portrays the observed weather patterns in their service territory. This definition of “normal” weather is then employed throughout the forecast horizon, implying that an “abnormal” weather outlook would not be an assumption and would not be a factor in projecting load. All utilities assumed a “normal” weather outlook.

The economic outlook of the local and national economy was obtained from several reputable economic forecasting firms such as *Global Insight*, *Woods and Poole*\(^\text{13}\), and *Moody's Economy.com*. The utilities across the State are nearly divided evenly among the three. All three firms are highly regarded in the industry. By using more than one firm, the risks of producing flawed results were minimized because somewhat different economic perspectives were relied upon.

**Outputs**

To assess the quality of the load forecasts, two measures were employed. The current forecast was compared to: (1) the prior forecast developed last year, and (2) the recent historical past. The 2016 Regional load forecast is lower than the 2015 forecast primarily due to more utilities capturing appliance efficiencies in their forecasting models or using more updated appliance efficiency assumptions.

The NEL is forecasted to be lower than the forecast provided last year throughout the forecast period. The current compound annual growth rate (CAGR) for NEL is 0.8% for the forecast period. The winter peak demands are forecasted to be lower than the forecast provided last year throughout the forecast period. For firm winter peak demands, the CAGR is expected to be 1.0% for the forecast period. The summer peak demands are forecasted to be initially higher than the forecast provided last year until 2019 when they are forecasted to be below what was provided last year. For firm summer peak demands, the CAGR is expected to be 1.1% for the forecast period.

**Load Factor**

Several other ad-hoc measures were examined to assist in the determination of the reasonableness of the load forecast. The load factor, which is the relationship between the average load and the peak

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\(^{10}\) Bureau of Economic and Business Research ([http://www.bebr.ufl.edu/](http://www.bebr.ufl.edu/))

\(^{11}\) Moody's Economy.com ([http://www.economy.com](http://www.economy.com))

\(^{12}\) Global Insight ([http://www.globalinsight.com](http://www.globalinsight.com))

\(^{13}\) Woods and Poole ([http://www.woodsandpoole.com/](http://www.woodsandpoole.com/))
load, was examined comparing projected and historical values for this parameter. The resulting confirmation that historical and projected load factors were aligned helped to provide an increased level of assurance that no given component of the load forecast was out of line. While historic load factor figures can be influenced by extreme temperatures in the hour of the annual peak, all member utilities exhibited reasonable load factors when comparing these values in the historical and projected periods.

Results

The comparison between the 2015 and 2016 forecasts for summer and winter peaks are shown in Table 2.

<table>
<thead>
<tr>
<th>Year</th>
<th>Summer Peak Forecast</th>
<th>Summer Peak Difference</th>
<th>Winter Peak Forecast</th>
<th>Winter Peak Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
<td>2016</td>
<td>MW</td>
<td>%</td>
</tr>
<tr>
<td>2016</td>
<td>47,304</td>
<td>47,654</td>
<td>350</td>
<td>0.7%</td>
</tr>
<tr>
<td>2017</td>
<td>48,097</td>
<td>48,125</td>
<td>28</td>
<td>0.1%</td>
</tr>
<tr>
<td>2018</td>
<td>48,784</td>
<td>48,648</td>
<td>-136</td>
<td>-0.3%</td>
</tr>
<tr>
<td>2019</td>
<td>49,498</td>
<td>49,266</td>
<td>-232</td>
<td>-0.5%</td>
</tr>
<tr>
<td>2020</td>
<td>50,133</td>
<td>49,873</td>
<td>-260</td>
<td>-0.5%</td>
</tr>
<tr>
<td>2021</td>
<td>50,756</td>
<td>50,461</td>
<td>-295</td>
<td>-0.6%</td>
</tr>
<tr>
<td>2022</td>
<td>51,378</td>
<td>50,973</td>
<td>-405</td>
<td>-0.8%</td>
</tr>
<tr>
<td>2023</td>
<td>52,074</td>
<td>51,514</td>
<td>-560</td>
<td>-1.1%</td>
</tr>
<tr>
<td>2024</td>
<td>52,837</td>
<td>52,125</td>
<td>-712</td>
<td>-1.3%</td>
</tr>
</tbody>
</table>

One key point presented in Table 2 is that the Region continues to project significant growth in peak load even though, in general, the projected growth is less than in the previous forecast. With regard to the 2016/17 winter peak, the 2016 forecast is lower than the 2015 forecast by approximately 1.1%. The 2015/16 winter peak was 38,187 MW which was 7,413 MW (16.3%) below what it was projected to be under normal weather conditions in the previous year’s forecast. In order to ensure that the starting point of the forecast is consistent with the latest historical value, an additional year of data is updated in each utility’s models and the most recent correlations and associations embedded in the historical data are captured and the models are calibrated accordingly.

The actual 2015 summer peak was 45,867 MW which was 1.3% (585 MW) lower than projected. The 2016 projections for summer peak demand, compared to the 2015 forecast, show an increase in 2016 of 0.7%, (350 MW) greater than projected; this is weather driven. Over the last ten years of actuals, peninsular Florida had a CAGR of 0.1% for summer peak demand. The current ten-year projection has a CAGR of 1.1%. In the load forecast evaluation process, FRCC ensured that all the utilities also adjusted the starting value of the summer peak demand forecast to account for the most recent correlations embedded in the historical data.

Included in these results are the impacts of energy conservation. Utility-sponsored Energy Efficiency/Energy Conservation programs will reduce the summer peak (MW) by 1.4% by 2025 and will reduce the winter peak
(MW) by 1.2% by 2025/26. Energy Efficiency delivered through mandated codes and standards\textsuperscript{14} will reduce the summer peak (MW) by at least an additional 4.8% by 2025 and the winter peak (MW) by at least an additional 2.6% by 2025/26.

The confidence level that can be placed on these forecasts can be deduced by examining the historical performance of FRCC’s forecasts. The summer peak analysis of the forecasted peaks versus the actual peaks, shown in Table 3, indicates that since 2006 there has been a tendency to over-forecast the summer peak demand in the FRCC aggregate ten-year load forecast.

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual Summer Peak (MW)</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>45,344</td>
<td>45,520</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>2007</td>
<td>46,525</td>
<td>46,725</td>
<td>46,878</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>2008</td>
<td>44,706</td>
<td>48,030</td>
<td>48,037</td>
<td>47,364</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>2009</td>
<td>46,260</td>
<td>49,233</td>
<td>49,280</td>
<td>48,181</td>
<td>45,734</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>45,564</td>
<td>50,221</td>
<td>50,249</td>
<td>49,093</td>
<td>45,794</td>
<td>46,006</td>
<td></td>
<td></td>
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<tr>
<td>2011</td>
<td>44,777</td>
<td>51,343</td>
<td>51,407</td>
<td>50,284</td>
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<td>46,124</td>
<td>46,091</td>
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<tr>
<td>2012</td>
<td>43,946</td>
<td>52,490</td>
<td>52,464</td>
<td>51,499</td>
<td>47,423</td>
<td>46,825</td>
<td>46,658</td>
<td>45,613</td>
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<tr>
<td>2013</td>
<td>44,549</td>
<td>53,686</td>
<td>53,548</td>
<td>52,645</td>
<td>48,304</td>
<td>47,469</td>
<td>47,446</td>
<td>46,270</td>
<td>45,668</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>45,794</td>
<td>54,830</td>
<td>54,622</td>
<td>53,641</td>
<td>49,219</td>
<td>48,059</td>
<td>48,228</td>
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<td>46,338</td>
<td>45,759</td>
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<tr>
<td>2015</td>
<td>45,867</td>
<td>56,130</td>
<td>55,896</td>
<td>54,862</td>
<td>50,280</td>
<td>48,699</td>
<td>49,278</td>
<td>47,758</td>
<td>47,053</td>
<td>46,719</td>
<td>46,452</td>
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</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual Summer Peak (MW)</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>45,344</td>
<td>-0.4%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>46,525</td>
<td>-0.4%</td>
<td>-0.8%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>44,706</td>
<td>-6.9%</td>
<td>-6.9%</td>
<td>-5.6%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>46,260</td>
<td>-6.0%</td>
<td>-6.1%</td>
<td>-4.0%</td>
<td>1.2%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>45,564</td>
<td>-9.3%</td>
<td>-9.3%</td>
<td>-7.2%</td>
<td>-0.5%</td>
<td>-1.0%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>44,777</td>
<td>-12.8%</td>
<td>-12.9%</td>
<td>-11.0%</td>
<td>-3.5%</td>
<td>-2.9%</td>
<td>-2.9%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>43,946</td>
<td>-16.3%</td>
<td>-16.2%</td>
<td>-14.7%</td>
<td>-7.3%</td>
<td>-6.1%</td>
<td>-5.8%</td>
<td>-3.7%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>44,549</td>
<td>-17.0%</td>
<td>-16.8%</td>
<td>-15.4%</td>
<td>-7.8%</td>
<td>-6.2%</td>
<td>-6.1%</td>
<td>-3.7%</td>
<td>-2.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>45,794</td>
<td>-16.5%</td>
<td>-16.2%</td>
<td>-14.6%</td>
<td>-7.0%</td>
<td>-4.7%</td>
<td>-5.0%</td>
<td>-2.3%</td>
<td>-1.2%</td>
<td>0.1%</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>45,867</td>
<td>-18.3%</td>
<td>-17.9%</td>
<td>-16.4%</td>
<td>-8.8%</td>
<td>-5.8%</td>
<td>-6.9%</td>
<td>-4.0%</td>
<td>-2.5%</td>
<td>-1.8%</td>
<td>-1.3%</td>
</tr>
</tbody>
</table>

Values are non-coincident peaks

\textbf{Table 3}

\textit{Comparison of Summer Peak Forecasts to Actual Peaks and Forecast Variance}

\textsuperscript{14} Only some utilities were able to quantify the impacts of Energy Efficiency delivered through mandated codes and standards; therefore, the full impact of mandated codes and standards is understated.

Classification: Public
The first column in Table 3, labeled “Actual Summer Peak (MW)”, corresponds to the actual non-coincident summer peak. The next ten columns show the forecast as it was presented in the Regional Load & Resource Plan for each of the ten years listed from 2006 to 2015. The bottom half of the table is the percent forecast variance, derived by comparing actual to forecast demands. A positive variance means that the “actual” was larger than the forecasted value for the corresponding year, meaning an under-forecast. A negative forecast variance means an over-forecast.

The forecast variance section of the table shown in Table 3 provides additional information. For example, in looking at the forecast variance in percentage terms, as the actual year nears the forecasted year the percentage variance tends to become smaller because better data and tools are available as each year passes.

The housing boom experienced in Florida created an abnormal cyclical upswing for the Florida economy that drove growth above normal trended levels expected in projections completed years earlier. The FRCC’s 2006 and 2007 forecasts missed their 2006 and 2007 targets by only -0.4% and -0.8%, respectively. At the time, these predictions were made, the housing boom was near its peak and many forecasters were predicting a correction in terms of a slower rate of expansion. The housing bust now lends some credence that a disequilibrium situation existed in the Florida economy during 2006 – 2007 that would never have been projected.

Similarly, the extent of the sudden and sharp decline in customer growth and energy consumption that occurred in 2008 was not foreseeable in the 2006 through 2008 forecasts. Although FRCC members predicted a slowdown in 2008, the extent of the downturn was more severe than expected. The smaller forecast variances in 2009 and 2010 were due to the recalibration of the forecasting models to reflect the economic downturn.

An unpredicted downturn is also evident for the summer peak in 2011. While the economy seemed to be showing signs of a recovery in 2010 and 2011, the reality was that average demand had continued to decline. Loads in 2011, 2012 and 2013 were significantly lower, resulting in a summer peak load variance of -2.9%, -3.7% and -2.5% respectively. Utilities recalibrated their forecasting models to account for the continual declines in per-customer usage which was not being fully captured in the previous forecast models. The 2014 summer peak load deviated from the forecast by 0.1% which was fantastic for the amount of volatility that can occur in any given year. The summer peak load in 2015 was 1.3% below what was predicted. However, that small of a variation is widely accepted throughout the forecasting community.

Over the short-term, customer growth and economic conditions can differ from the long-term assumptions used to develop the forecast. Predicting cyclical economic “turning points” is a very difficult part of the utility forecaster’s job. The FRCC forecast does not attempt to capture these short-term deviations, but seeks to portray the most likely outcome in terms of projected load for the state of Florida over the next ten years.
The analysis for winter peaks is shown on Table 4. A perfunctory review noting the negative values would suggest a tendency to over-forecast given the predominance of projected peaks higher than the observed “actuals”. Weather and temperature variations typically differ from the “normalized” weather assumptions used to develop the individual utility electric forecasts. In Florida, this is much more pronounced for the winter months compared to the summer months. Therefore, this weather volatility caused a significantly larger number of over-forecast occurrences because since 1999 there has been only two years, 2003 and 2010, with normal or colder than normal winter seasons for the State of Florida as a whole. A good example of this volatility can be seen comparing the actual peaks of 2006/07 and 2009/10. Winter 2006/07 had a mild winter and the total winter demand of electricity was 38,023, which was 5,179 MW (12%) lower than in the prior

Values are non-coincident peaks

**Table 4**

*Comparison of Winter Peak Forecasts to Actual Peaks and Forecast Variance*

The analysis for winter peaks is shown on Table 4. A perfunctory review noting the negative values would suggest a tendency to over-forecast given the predominance of projected peaks higher than the observed “actuals”. Weather and temperature variations typically differ from the “normalized” weather assumptions used to develop the individual utility electric forecasts. In Florida, this is much more pronounced for the winter months compared to the summer months. Therefore, this weather volatility caused a significantly larger number of over-forecast occurrences because since 1999 there has been only two years, 2003 and 2010, with normal or colder than normal winter seasons for the State of Florida as a whole. A good example of this volatility can be seen comparing the actual peaks of 2006/07 and 2009/10. Winter 2006/07 had a mild winter and the total winter demand of electricity was 38,023, which was 5,179 MW (12%) lower than in the prior
winter. Conversely, winter 2009/10 was very cold and the winter demand for electricity reached a record of 51,767 MW of peak winter demand. The 2009/10 winter peak load was 6,177 MW (14%) above the prior winter’s peak and 7,321 MW (16.5%) above the forecasted winter peak. This extremely high winter peak was the result of the high energy consumption of heating appliances in use as customers attempted to stay warm when temperatures dipped lower than had been experienced in many years. Temperatures on the winter peak day ranged from 17 to 38 degrees Fahrenheit throughout the state.

Florida does not experience a cold winter very often. Nevertheless, each utility in its resource plan considers the eventuality of a severe winter peak and plans for it. The winter of 2009/10 turned out to be the coldest winter on record (or very close) in many areas of peninsular Florida. Utilities utilized a number of their load management/demand response programs in order to serve their firm load throughout the peak load period. Conversely, the 2015/16 winter peak was 16.3% below forecast due to hotter weather during the winter months where heating load is predicted. Heating load tends to use more energy than cooling load.

Finally, Table 5 shows a comparison between the historical load factors (for 2006 through 2015), and the projected load factors (for 2016 through 2025), based on the summer peak. The summer peak was chosen for this calculation because it is less volatile than the winter peak, which fluctuates widely over the historical years because cold winters have occurred only sporadically. Both historical and forecasted load factors are similar in magnitude. Projected load factors are slightly lower than what has been reported historically, due to peak demand growing slightly faster than Net Energy for Load.

<table>
<thead>
<tr>
<th>Historical Year</th>
<th>Load Factor</th>
<th>Forecasted Year</th>
<th>Load Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>0.579</td>
<td>2016</td>
<td>0.550</td>
</tr>
<tr>
<td>2007</td>
<td>0.571</td>
<td>2017</td>
<td>0.548</td>
</tr>
<tr>
<td>2008</td>
<td>0.579</td>
<td>2018</td>
<td>0.546</td>
</tr>
<tr>
<td>2009</td>
<td>0.558</td>
<td>2019</td>
<td>0.544</td>
</tr>
<tr>
<td>2010</td>
<td>0.584</td>
<td>2020</td>
<td>0.543</td>
</tr>
<tr>
<td>2011</td>
<td>0.571</td>
<td>2021</td>
<td>0.541</td>
</tr>
<tr>
<td>2012</td>
<td>0.574</td>
<td>2022</td>
<td>0.540</td>
</tr>
<tr>
<td>2013</td>
<td>0.568</td>
<td>2023</td>
<td>0.539</td>
</tr>
<tr>
<td>2014</td>
<td>0.560</td>
<td>2024</td>
<td>0.537</td>
</tr>
<tr>
<td>2015</td>
<td>0.584</td>
<td>2025</td>
<td>0.534</td>
</tr>
</tbody>
</table>

Table 5
FRCC Load Factors

Forecasting models and methodologies used for developing energy sales and peak demand forecasts are delivering current projections that appear reasonable based on historical data and recent forecasts. The inputs and assumptions were also reasonable and appropriate given current trends. As a result of this evaluation, the FRCC LFWG concludes that the load forecast is suitable and reasonable for use in reliability assessment analyses.
8.0 FRCC Transmission

The FRCC Region participants perform various transmission planning studies addressing NERC Transmission Planning (TPL) Reliability Standards. These studies include short-term and longer term transmission studies and seasonal assessments as well as additional sensitivity studies as needed to address specific issues (e.g., extreme summer weather, off-peak conditions), interconnection and integration studies, and interregional assessments.

The results of the short-term (first five years) study of the FRCC Region for normal, single, and multiple contingency events show that potential thermal and voltage constraints occurring within the FRCC Region are capable of being managed successfully by operator intervention. Such operator intervention can include: generation re-dispatch, system reconfiguration, reactive device control, load shed, and transformer tap adjustments. The majority of planned additions or changes to the FRCC transmission system is related to planned generation expansion and expected load growth.

The longer-term study is performed to identify potential constraints requiring longer lead-time projects. The longer-term study allows entities to evaluate multiple project alternatives. No major 500 kV transmission projects requiring long lead time have been identified.
9.0 FRCC Fuel Reliability

The FRCC Generating Capacity Shortage Plan\(^\text{15}\) distinguishes between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (e.g., hurricane impacts to fuel or abnormally high loads) in order to provide more effective Regional coordination. The FRCC plan also includes specific actions to address capacity constraints due to natural gas availability constraints and includes close coordination with the pipeline operators serving the Region. The FRCC Operating Committee (OC) has a procedure in place with details regarding the coordination between the FRCC Reliability Coordinator (RC) and the natural gas pipeline operators. In addition, the FRCC Operating Reliability Subcommittee (ORS), through its Fuel Reliability Working Group (FRWG) continues to periodically review and assess various aspects of the current fuel supply infrastructure in terms of reliability for generating capacity.

For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC) along with the FRCC RC have the ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by operating entities. This process relies on entities to report their actual and projected fuel availability, along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC and is provided on a Regional basis to the RC and SCEC. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and the results of the reporting are quickly integrated into an enhanced FRCC Daily Capacity Assessment Procedure & Definitions process along with various other coordination protocols. These processes help improve the accuracy of the reliability assessments of the Region and ensure coordination to minimize impacts of Regional fuel supply issues and/or disruptions on Bulk Electric System (BES) facilities and customers.

Currently, the expected percentage of generation capacity (MW) whose primary fuel is natural gas is projected to reach 69.1% by 2025. A similar long-term forecast projects coal-fired generation to account for 13.4% of capacity, nuclear generation for 6.3%, and oil-fired generation for 9.6% of generation resources. About 1.6% of capacity generation is fueled from Municipal Solid Waste (MSW), Inter-Regional interchange, and miscellaneous fuels.

In regard to the percentage of total electrical energy (GWh) provided by natural gas, the use of natural gas is currently projected to remain high through the next ten years and will reach 65.2% by 2025.

With no native gas production or storage, two major pipelines deliver more than 90% of the natural gas to peninsular Florida. The existing pipeline capacity within the Region supports the current generating capacity needs of the Region. In the event of a short term failure of key elements of natural gas delivery infrastructure, there is sufficient back up fuel capability to meet projected demand. However, additional coordination may be required in the event of a long-term failure of key elements of natural gas delivery infrastructure.

Regional operators continue to utilize mitigation strategies to minimize the effects of short-term supply impacts due to extreme weather during peak load conditions. These strategies include fuel supply and transportation diversity as well as alternate fuel capabilities. Absent long-term transportation outages, and

\(^\text{15}\)FRCC Generating Capacity Shortage Plan (http://www.psc.state.fl.us/library/filings/08/04959-08/04959-08.pdf)

Classification: Public
based on current fuel diversity, alternate fuel capability and on-going coordination efforts, the FRCC does not anticipate any fuel transportation issues that will affect BES reliability during peak periods and/or during extreme weather conditions in the near-term.
10.0 FRCC Renewables Energy Resources

Nationally, the definition of renewable energy resources varies from state to state. While almost all states treat solar and wind as renewable resources, many states differ on the applicability of other forms of renewable resources such as municipal solid waste (MSW) facilities and some types of hydroelectric and waste heat from cogeneration facilities. The State of Florida has defined the term “Renewable Energy” in Florida Statute 366.91 as “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.” Furthermore, the term “Biomass” is defined as “a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts or products from agricultural and orchard crops, waste and co-products from livestock and poultry operations, waste and byproducts from food processing, urban wood waste, municipal solid waste (MSW), municipal liquid waste treatment operations, and landfill gas.”

Twenty-nine states and Washington, D.C. have adopted a Renewables Portfolio Standard (RPS) and eight states have set renewable energy goals as of March 2016. Although the State of Florida does not have a Renewable Portfolio Standard (or a Clean Energy Standard), a portion of its energy is derived from renewable resources and a significant amount of energy, approximately 12%, is produced by emissions-free nuclear energy.

Renewable energy electric production in 2015 for peninsular Florida was 3,301 GWh. Municipal solid waste (42.5%), biomass (36.3%), landfill gas (9.8%), and solar (6.1%) provided the bulk of this 2015 renewable energy production as seen in Figure 6 below. Wind resources, a significant renewable energy contributor in many other states, are insignificant in Florida. This essentially eliminates the potential for renewable energy from wind in this state.

However, based on the utilities’ TYSPs, renewable energy production in peninsular Florida is projected to grow to 4,908 GWh by 2025 which represents approximately a 50% increase in the contribution from renewables. Perhaps, even more important is the 1200% increase in the contribution from solar: from 200 GWh in 2015 to 2,600 GWh in 2025. Figure 7 provides the projected values for 2025. FRCC and individual entities continue to monitor and evaluate penetration levels of renewable resources to ensure system reliability.

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Figure 6
FRCC Renewable Energy Sources in 2015

Figure 7
FRCC Renewable Energy Sources Projected for 2025

Classification: Public
11.0 References

11.1 2016 Regional Load & Resource Plan

12.0 Review and Modification History

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<th>Version Number</th>
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<th>Sections Affected</th>
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<td>New document</td>
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</table>

13.0 Disclaimer

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