BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	)))))	DOCKET NO. ________________ Submitted for filing: May 27, 2014

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING

Duke Energy Florida, Inc. ("DEF" or the "Company") hereby gives notice of filing the Direct Testimony of Benjamin M.H. Borsch with Exhibits BMHB-1 through BMHB-11 in support of DEF's Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

Respectfully submitted this 27th day of May, 2014.

*_/s/ James Michael Walls_*

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. _____________ Submitted for filing: May 27, 2014

DIRECT TESTIMONY
OF BENJAMIN M. H. BORSCH

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

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IN RE: PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. _________

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name, employer, and business address.

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the

Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the Director, IRP & Analytics – Florida, I oversaw the completion of the Company's most recent TYSP document filed in April 2014 and the Company's 2013 TYSP. I was also responsible for the Company's evaluation of options to meet its needs for reliable electric power prior to 2018.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009 I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy accepted my current position. Prior to joining Progress Energy, I was employed for more than 5 years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas fired power plant projects in nine states. I was also employed for more than 8 years as an environmental consultant with projects including development, permitting and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of the Company in support of its Petition for Determination of Cost Effective Alternative to Meet Need prior to 2018 for Duke Energy Florida. I will provide an overview of the generation alternatives that the Company proposes to build to meet its need prior to 2018 in the most cost-effective manner for its customers. I will discuss the resource planning process and how that led the Company to identify this need prior to 2018 and I will explain the steps the Company took to identify available, potentially superior supply-side alternatives. Next, I will explain the Company's evaluation of these generation alternatives and set forth the reasons why the Company's self-build generation options are the most cost-effective resource options to meet the Company's need prior to 2018. I will conclude my testimony by explaining the Company's decision to proceed with its self-build generation options to meet its need prior to 2018 in the most cost-effective manner for the Company's customers.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (BMHB-1), a copy of the Florida Reliability Coordinating Council ("FRCC") Evaluation of Transmission Impact of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") --- Transmission Impact Study for Shutdown of Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") with retirement of Crystal River Unit 3 ("MATS Study");
- Exhibit No. ___ (BMHB-2), the Company's current, April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), the Company's near-term summer and winter load forecast;
- Exhibit No. ___ (BMHB-4), the Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-5), the Company's forecast of physical and dispatchable demand-side resource reserves through the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-6), the generation options evaluated to contribute to the Company's capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-7), a confidential chart of the supply-side generation proposals evaluated by the Company to meet its capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-8), the Company's initial detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summers of 2016 and 2017;

- Exhibit No. ___ (BMHB-9), the Company's cost sensitivity analysis results based on the initial detailed economic analysis;
- Exhibit No. ___ (BMHB-10), the Company's final detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summer of 2016 and 2017; and
- Exhibit No. ___ (BMHB-11), the Company's analysis of natural gas price and carbon cost ("CO2") sensitivities to the final detailed economic analyses.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively, to meet its 20 percent Reserve Margin commitment and to serve its customers' future electrical power needs in a reliable and cost-effective manner. Faced with generation plant retirements and additional customer and peak load demand, the Company determined in its resource planning process that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were superior to any other alternative, including additional renewable energy resources and conservation measures, to meet the Company's near-term generation capacity needs.

The Company further evaluated these projects against power purchase agreement and generation facility acquisition proposals from third-party generators, and none of these proposals compared more favorably, on a quantitative and qualitative basis, to the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. DEF has demonstrated that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the best alternatives for maintaining DEF's electric system reliability and integrity, and providing its customers with adequate electricity at a reasonable cost, by the summer of 2016 and 2017, respectively. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

III. OVERVIEW OF THE COMPANY'S NEED AND PETITION.

Q. Can you generally explain the Company's need that led to this Petition?

A. Yes. The Company faced resource planning decisions leading up to and early in 2013 that affected the Company's near-term need in the ten-year planning period for generation capacity to meet customer energy needs. As a result, during the Company's annual integrated resource planning analysis, the Company identified substantial generation capacity needs in the near term, beginning in 2016. This analysis was first reflected in the Company's 2013 TYSP. The Company's continuing resource planning process and analysis that resulted in its 2014 TYSP confirmed this need beginning in 2016.

Q. What were these resource planning decisions?

A. In February 2013, the Company decided to retire its Crystal River Unit 3 nuclear power plant ("CR3"). The Company also decided to retire its CR1 and CR2 (also "CRS" for "Crystal River South"), coal plants earlier than originally planned. These generation retirements account for over 1,500 MegaWatts ("MW") of summer generation capacity on DEF's system.

The Company planned to retire its CR1 and CR2 coal plants in 2020. The issuance of new EPA environmental regulations under the Clean Air Act affected the Company's planned retirement of CR1 and CR2. As a result of these new environmental regulations, the Company faced the retirement of CR1 and CR2 as soon as 2015, but, as explained in more detail below, the Company now plans to retire CR1 and CR2 in 2018. Still, these and other retirement decisions and the Company's response to them, coupled with the Company's load growth, create a near term need for generation, commencing in 2016.

Q. What were the environmental regulations that impacted the Company's planned retirement of its Crystal River South coal plants?

A. The EPA issued its MATS regulations in December 2011 and these regulations became effective in April 2012. The EPA MATS regulations are designed to reduce mercury, other metals, and acid gas emissions from coal- and oil-fired power plants. Compliance with MATS is required three years after the effective date, or by April 2015. A one-year MATS compliance extension is available under certain conditions from the Florida Department of Environmental

Protection ("FDEP"). The Crystal River Units 1 and 2 coal-fired units cannot meet the emissions requirements for MATS as currently configured and without changes in the coal fuel source for the units.

Q. What impact did these EPA regulations have on the Company's retirement decision for its Crystal River South coal plants?

A. Initially, the Company faced the retirement of CR1 and CR2 as early as 2015, with a possible extension to 2016. This extension was granted by the FDEP earlier this year, based on the time DEF needed to complete modest upgrades to the CR1 and CR2 units under a plan the Company developed for limited continued operation of CR1 and CR2 in compliance with MATS. The FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant Florida electric grid reliability issues identified by the FRCC in its MATS study completed in 2013.

The FRCC MATS Study evaluated the impact of a MATS-required shutdown of CR1 and CR2 on the reliability of the Florida Bulk Electric System ("BES"). The FRCC is responsible for ensuring that the Florida BES is reliable and adequate. The FRCC concluded, based on its analysis in 2013, that shutting down CR1 and CR2 in 2015 as a result of MATS would result in significant, adverse transmission impacts to the BES. The FRCC found that, at a minimum, the one-year extension of the MATS compliance deadline was needed to provide time to alleviate the significant transmission reliability issues that the FRCC identified in the MATS Study. The FDEP considered the FRCC conclusions in its decision to grant the one-year extension to 2016 for CR1 and CR2 to comply with MATS. A copy of the FRCC MATS Study is attached as Exhibit No. ___ (BMHB-1) to my direct testimony.

During 2013, the Company further evaluated the continued operation of Crystal River South in compliance with MATS and other environmental regulations and determined that the Company could continue to operate CR1 and CR2 beyond 2016 with certain modifications to the units and a change to lower sulfur coal blends burned at the plants. The Company evaluated this plan against other options, concluded that the plan was the most cost-effective option, and presented this plan to the Commission in December 2013 as a modification to its Integrated Clean Air Compliance Plan. More detail on the Company's compliance strategy for CR1 and CR2 in response to MATS and other environmental regulations is provided in the Company's petition to modify its Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI. The Commission approved this modification to its Integrated Clean Air Compliance Plan in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014).

The Company now plans to continue commercial operation of CR1 and CR2 until 2018 in compliance with the Commission-approved modification to its Integrated Clean Air Compliance Plan. This decision reduces the generation capacity the Company needs prior to 2018, but the Company still needs generation capacity to reliably serve its customers commencing in this time period.

Q. What were the Company's other generation retirement decisions?

A. The Company projected the retirement of some of its oldest combustion turbines in its fleet in 2014 and 2016. These projected retirements were identified in the Company's resource planning process in the late 2000's and continued to be part of the Company's resource plans in its 2013 and 2014 TYSPs. These combustion turbines were installed in the late 1960's and early 1970's at Avon Park, Turner, and Rio Pinar. They collectively provide 133 MW of summer generation capacity to DEF's system. They are smaller, less efficient combustion turbines and they are increasingly more costly to operate and maintain. The Company will retire all of these combustion turbine units by 2016.

The Company also plans to retire its three 1950's vintage oil- and gas-fired steam generation plants at the Company's Suwannee power plant site by 2016. These are small units, collectively providing 128 MW of summer capacity to DEF's system. These units were slated for retirement in 2018 as they approach the end of their life cycle. DEF will retire these units in 2016 to reduce the cost of the transmission upgrades needed for installation of the proposed peakers.

These generation plant retirements contribute to the Company's generation capacity needs prior to 2018. Coupled with load growth identified in the Company's 2013 and 2014 TYSPs, the Company needs additional generation capacity prior to 2018 to reliably serve customers.

Q. What did the Company do in response to this identified need in 2016?

A. The Company evaluated several alternative generation options to meet this need including (i) construction of new generation; (ii) purchases from or acquisitions of existing generation plants owned by other companies; and (iii) power uprate projects at existing generation plants on the Company's system. The Company identified a need up to 1,150 MegaWatts ("MW") of additional generation capacity beginning in 2016 and established a process for Commission review of the Company's evaluation of this need in its Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement"). In the 2013 Settlement, the Company agreed to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 through its Integrated Resource Planning ("IRP") methodology and to present this evaluation to the Commission.

Q. Does the Company still need up to 1,150MW of generation commencing in 2016?

A. No. As I explained above, the Company's decision to complete projects necessary to permit the continued operation of CR1 and CR2 with alternative, low sulfur coal fuel sources and site averaging to comply with MATS extends the operation of CR1 and CR2 to 2018. This decision reduces the Company's generation capacity needs commencing in 2016. As a result, the Company no longer needs up to 1,150 MW of generation capacity commencing in 2016. The Company's need now is approximately 280 MW of summer generation capacity commencing in 2016 that increases to 470 MW in the summer of 2017.

Q. What is the Company's plan to meet its generation needs commencing in 2016?

A. The most cost-effective resource plan to meet the Company's summer generation capacity needs commencing in 2016 includes the construction of a new 320 MW simple cycle combustion turbine plant consisting of two F class combustion turbine units at the Company's Suwannee power plant site. This is called the Suwannee Simple Cycle Project. This plan also includes the installation of a 220 MW chillers power uprate project for the Company's existing natural gas-fired, combined cycle power blocks at the Company's Hines Energy Complex ("HEC"). This is called the Hines Chillers Power Uprate Project. This is the most cost-effective generation resource plan available to the Company for its customers to meet the Company's near-term generation needs commencing in 2016 based on both price and non-price attributes.

Q. Is the Company's decision with respect to its generation needs prior to 2018 consistent with the 2013 Settlement Agreement?

A. Yes. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the types of generation options specifically contemplated in the 2013 Settlement Agreement to meet the Company's generation capacity needs prior to 2018. The Company's decision to select these projects to meet its reliability need is the result of the IRP methodology that the Company agreed in the 2013 Settlement Agreement to use to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 and present to the Commission for approval. Indeed, the parties to the 2013 Settlement Agreement agreed that DEF could seek Commission approval for the costs of additional generation to meet a need up to 1,150 MW in the 2013 Settlement Agreement, however as I explained above, the Company's ability to cost-effectively comply with MATS and extend the commercial operation of Crystal River South has reduced the Company's estimated need prior to 2018 from up to 1,150 MW to approximately 500 MW. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost-effective generation options to meet that need.

DEF has met with the parties to the 2013 Settlement Agreement several times to explain DEF's approach to its generation needs prior to 2018 and, ultimately, DEF's analyses and decision to meet that need consistent with the terms of the 2013 Settlement Agreement. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain the Company's Resource Planning Process.

A. The IRP process is an integrated process in which the Company seeks to optimize its supply-side and demand-side options into an integrated optimal plan designed to deliver reliable, cost-effective power to DEF's customers. On an annual basis, and when circumstances materially affecting the Company's current resource plan change, we evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed. Based on that evaluation, we develop the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This Integrated Optimal Plan is typically presented to the Commission in April each year in the Company's annual TYSP filing. The Company's current 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What reliability standards does the Company use to determine the need for additional resources?

A. DEF plans its resources in a manner consistent with utility industry resource planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF has used dual reliability criteria since the early 1990s in its IRP process and this practice has been accepted by the Commission. DEF uses both the Reserve Margin and LOLP planning criteria to ensure that its resource plan has sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions in the Company's service territory.

Q. Why are reserves needed?

A. Utilities require reserves to provide a margin of generating capacity above the firm demands of their customers in order to provide reliable electric service.

Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. Also, at any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis. For all these reasons, DEF plans generating capacity reserves into its optimal resource plan.

Q. What is DEF's Reserve Margin in its Integrated Resource Plan?

A. DEF's current minimum Reserve Margin threshold is 20 percent. The Reserve Margin is a deterministic measure of reliability. Reserve margin is the amount of capacity that a utility maintains above the peak forecast load expressed as a percentage of the load. The Commission approved this minimum Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Commission Order No. PSC -99-2507-S-EU.

Q. What is LOLP and what does it measure?

A. The LOLP is a probabilistic criterion that measures the probability that a utility company will be unable to meet its load throughout the year. Where Reserve Margin considers only the peak load and amount of installed resources, LOLP also takes into account a utility's load shape, generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard LOLP probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability. In most cases, however, the need for additional generation capacity is triggered by the 20 percent Reserve Margin requirement before the LOLP criterion is considered. DEF's need for additional generation capacity prior to 2018 is also based on DEF's 20 percent Reserve Margin requirement.

Q. How did you start your resource plan that led to the identification of your need beginning in 2016 based on your reliability criteria?

A. As I explained above, there were certain retirement decisions, in particular, the retirement of the Company's CR3 nuclear plant, and the planned retirement of the Company's Crystal River South coal plants around changing environmental requirements, that drove the Company's near-term reliability needs as the Company entered 2013. The generation capacity need resulting from these decisions was coupled with additional load growth as a result of the Company's routine update of its forecast of system load growth for the next ten years as part of the normal IRP process. The Company's load forecast draws on the collection of certain input data, such as population growth, fuel prices, and interest and inflation rates. The load forecast is then developed based on economic and demographic assumptions that impact future energy sales and customer demand. The Company's load forecast is another key driver of the Company's resource plan in the IRP process. The Company's load forecast methodology is described in detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Can you generally describe DEF's system demand and energy forecasts?

A. Yes. The Company's summer firm demand is expected to grow to 9,149 MW by the summer of 2016, which represents approximately a 3.8 percent growth rate from 2014. The net energy for load is projected to grow to 41,098 GWh in 2016, which represents approximately a 3.3 percent growth rate from 2014. The demand and energy forecasts are discussed in more detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What is the impact of the Company's load forecast on the Company's generation resource needs?

A. The Company will experience load growth as the Florida economy recovers from the last recession. DEF expects both more customers and growth in energy demand in the near term, through 2017, albeit at a slower pace than customer and energy demand growth before the recession. This is a change from the loss of customers and reduced demand at the height of the recession in 2009. The Company has slowly recaptured the ground lost during the recession and expects continued growth in customers and demand. This growth, especially in summer peak demand on the Company's system, is one driver of the need for additional generation. Additionally, as I explained above, the need for additional generation is driven by the Company's decisions to retire generation capacity on its system. Together, the Company's projected capacity needs resulting from the Company's projected load growth, and existing and planned retirements, among other factors, demonstrate a need for additional capacity of approximately 280 MW in the summer of 2016 increasing to a need for 470 MW by the summer of 2017. Exhibit No. ____ (BMHB-3) is a summary of the Company's summer load forecast during this period.

Q. What is the impact on the Company's Reserve Margin?

A. DEF needs additional generation in the summer of 2016 and 2017 to meet its 20 percent minimum Reserve Margin requirement. Exhibit No. ___ (BMHB-4) shows DEF's forecast of summer peak demand and reserves, with and without any summer capacity additions. For the period from the summer of 2015 to the summer of 2017, DEF projects that the growth in firm summer peak demand will average approximately 132 MW a year with a projected peak in 2016 of 9,149 MW and in 2017 of 9,307 MW. The exhibit also shows that DEF will have a total generating capability of approximately 11,012 MW by the summer of 2016 and 11,232 MW by the summer of 2017. This capacity includes the installation of the Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017.

As demonstrated in this exhibit, without these capacity additions, DEF's Reserve Margin will decrease to 16.9 percent in the summer of 2016 and 14.9

percent by the summer of 2017. DEF maintains its Reserve Margin for its summer (and winter) peak demands to ensure reliable electric service to its customers. DEF needs additional generation capacity in the summer of 2016 and the summer of 2017 to meet its obligation to provide reliable electric service to its customers.

Q. Did the Company consider non-generating alternatives to meet the Company's capacity need commencing in 2016?

A. Yes, energy conservation and direct load control programs are always a part of the Company's IRP process and they were considered in connection with the Company's near-term generation capacity need commencing in 2016. The Company's current demand-side management ("DSM") programs were included in the Company's Base Generation Expansion Plan that contains the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate project. As evidenced by the inclusion of these projects in the Company's Base Generation Expansion Plan, however, The Company's current DSM programs cannot replace or defer the Company's need for additional generation on its system to meet the Company's generation capacity needs commencing in 2016.

Q. What are the Company's current DSM programs?

A. DEF's current DSM programs were essentially set forth in the DSM Plan approved by the Commission in Order No. PSC-11-0347-PAA-EG in August 2011. In this Order, the Commission modified the Company's DSM Plan, effectively approving the Company's DSM programs that were in effect in August 2011. In 2012, additional revisions to four Company DSM programs resulting from changes in the Florida Building Code were approved, otherwise the Company's current DSM programs are the same as the programs the Commission approved in Order No. PSC-11-0347-PAA-EG. With these revisions, DEF's Commission-approved DSM Plan consists of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs. These DSM programs will continue to be offered to the Company's customers through 2014 as the Company's current DSM Plan extends through the end of the year. A more detailed description of the Company's DSM programs is contained in the Company's 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Did the Company's continuing IRP planning process in 2014 reveal new or revised DSM programs or measures that satisfied or deferred the Company's generation capacity needs commencing in 2016?

A. No. DEF performed the DSM evaluations necessary for the Commission's current DSM goals docket that will set DEF's future DSM goals for the period 2015 to 2024. Based on the results of that evaluation, there are no additional DSM measures or programs that can replace or defer the Company's need for additional generation capacity prior to 2018 to reliably serve DEF's customers. There is no reason to conclude, then, that the Company's determination that it needs additional supply-side generation capacity commencing in 2016 will be affected by the outcome of the current DSM goals docket.

Over the next ten years the Company's proposed conservation goals are generally lower than the existing DSM goals. All other things being equal, then, the Company's near-term DSM goals cause an increase in DEF's firm summer peak demand in 2016 and 2017, and, therefore, further establish the need for the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's reliability needs in 2016 and 2017.

DEF's proposed DSM Plan reflects the successful implementation of cost-effective DSM programs by the Company for the past thirty years to reduce energy demand and energy consumption and therefore avoid the need for new generation. Through 2011, DEF's Commission-approved DSM programs have achieved more than 5,000 GWh reductions in energy consumption and over 1,645 MW in demand savings, effectively eliminating the need for the Company to build and operate approximately eighteen (18) new peaking power plants. The elimination of the need to build additional generation plants has resulted in over $1.2 billion in customer energy savings.

Substantial reductions in energy consumption and demand already have been achieved by the Company in its service territory, necessarily resulting in diminishing future energy consumption and demand reductions from future energy efficiency programs and measures. It is simply more difficult to achieve additional reductions in energy consumption and demand, and more costly to do so too, with continued or new DSM programs. More simply put, DEF's past success with its DSM programs makes it more difficult to get more "bang for the buck" with new or revised DSM programs.

In addition, DEF's new DSM programs are competing with increasing gains in energy efficiency by measures implemented by customers themselves, either independently or as a result of other, non-utility incentives, such as building code changes for new customer construction. The Commission recognized this impact in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining to the Florida Legislature that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs. These impacts also make it more difficult and more costly to achieve each incremental increase in energy efficiency or demand reduction through DEF's DSM programs.

For all these reasons, as more fully explained by the Company in Docket No. 130200-EI, DEF's proposed DSM goals for the next ten years are lower than the Company's current DSM goals. As a result, the Company's proposed DSM goals have no impact on the Company's reliability need in 2016 and 2017. There simply are no cost-effective DSM measures or programs that can offset or defer the need for additional generation capacity beginning in 2016.

Q. Would the Company's reliability need in 2016 and 2017 be impacted if the results of the current DSM goals docket are different from what the Company expects them to be?

A. No. The Company firmly believes that its proposed DSM goals in Docket No.

130200-EI are reasonable, cost-effective goals for the Company and its customers, and that they will be accepted by the Commission. Even if the Commission for some reason departed from these proposed DSM goals, however, for several reasons the resulting goals would have no impact on the Company's reliability need in 2016 and 2017.

First, the future DSM goals will not even be established by Commission Order until the fall of 2014, at the earliest. The Company will then need time to evaluate, develop, and implement new or revise existing DSM programs and measures in an attempt to meet the new DSM goals. After these new or revised DSM programs and measures are implemented, there naturally will be a period of time before any results are observed in the Company's load and peak demand. The Company cannot obtain the new DSM goals, evaluate them, develop and implement new or revised DSM programs or measures to achieve those goals, and see the full results of these new or revised DSM programs or measures by the summers of 2016 and 2017 when the Company has a reliability need for new generation. Accordingly, even if the current DSM goals docket results in different, higher DSM goals for DEF than DEF has proposed in that docket, those DSM goals would have no impact on DEF's reliability need for additional generation capacity in the summer of 2016 and 2017.

Q. Are there other considerations in balancing demand- and supply-side resources?

A. Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. While dispatchable demand-side resources provide important and cost-effective resources to reduce load, they cannot be used as often or as long as physical generation without eventually affecting customer participation levels. Prolonged use of dispatchable DSM resources to meet customer load demand, especially in the summer months, will result in customer attrition in the dispatchable DSM program. Based on the Company's experience, when interruptions in customer service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, DEF carefully evaluates increasing reliance on dispatchable DSM programs to meet load with additional physical reserves to meet that load. In the case of the Company's additional capacity needs in the summers of 2016 and 2017, based on projected load growth and the Company's existing and planned generation retirements, the planned addition of generation projects will increase the Company's share of physical reserves to approximately 54 percent of total reserve capacity (which includes DSM) in the summer of 2017. See Exhibit No. ___ (BMHB-5) to my direct testimony. This level of physical reserves, in the Company's view, is, at a minimum, necessary to maintain coverage of an unplanned outage of the fleet's largest unit or to maintain coverage in an extreme weather event.

Q. Were supply-side alternatives identified and considered to meet the Company's capacity needs commencing in 2016?

A. Yes, in fact, the Company's optimization of its resource plan to meet its capacity needs commencing in 2016 in its IRP process determined that supply-side generation alternatives were necessary to cost-effectively meet customer capacity needs beginning in this time period. DEF examined several alternative generation expansion plans to meet this need, however, the alternative generation expansion plans that could be evaluated were limited by the need to place generation in-service in 2016 and 2017. With this limitation in mind, the Company evaluated generation options to determine those options that were the most cost-effective, screening the options based on cost, fuel sources and availability, technological maturity, and overall resource feasibility within the Company's system.

Generation alternatives that passed this screen were included in the Company's economic evaluation in the EPM production cost computer model. The primary output of EPM is a Cumulative Present Value Revenue Requirements ("CPVRR") comparison of the generation resource options that satisfied DEF's reliability requirements. The most cost-effective supply-side resources were evaluated and ranked by system revenue requirements. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project had the lowest CPVRR and were chosen by the Company as its Base Generation Plan to meet the Company's reliability needs in 2016 and 2017.

Q. Did the Company consider supply resources from other generation suppliers in its planning process to meet its capacity needs commencing in 2016?

A. Yes. DEF always takes into account the potential future supply of firm capacity from purchased power contracts during the study period in its evaluation. In fact, DEF determined that a short-term power purchase agreement ("PPA") with Southern Company over the limited transmission import interface was cost effective and included this purchase in its Base Generation Plan to meet its generation capacity needs commencing in 2016. DEF also evaluated several, other PPAs, and even acquisitions of generation facilities, to determine if they were more cost effective, considering all price and non-price attributes, than the Company's self-build new generation Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to meet the Company's capacity needs commencing in 2016. These other, potential generation alternatives, and the Company's evaluation of them, are discussed in more detail later in my direct testimony.

Q. Did the Company consider renewable energy sources and technologies to meet its capacity needs in 2016?

A. Yes. The Company evaluates the timelines for new technologies including renewable energy source and technologies on a continuing basis as part of its IRP process. The Company also has a Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects. The Company will continue to evaluate the development or purchase of renewable energy in the future to potentially reduce DEF's use of fossil fuels or to defer or eliminate the need to construct more conventional, fossil-fueled generation resources.

Q. Were renewable energy sources or technologies reasonably available to the Company to meet its capacity needs commencing in 2016?

A. No. No commercially available, economically feasible renewable generation resource currently exists to displace or defer DEF's generation capacity needs commencing in the summer of 2016. DEF has a contract with U.S. Ecogen for a 60 MW plant that will use an energy crop as a fuel source with a planned in-service date of January 2017, however, that in-service date is uncertain and, even if this plant achieves commercial operation in January 2017, it does not address DEF's generation capacity need commencing in the summer of 2016, and it does not defer the need for generation capacity in the summer of 2017. Additionally, no other proposal for renewable energy projects have been received in response to the Company's RFR that will displace or defer the Company's generation capacity needs in 2016 and 2017.

V. THE SUWANNEE SIMPLE CYCLE AND HINES CHILLERS POWER UPRATE PROJECTS.

Q. Please explain the Company's plan to meet its capacity needs commencing in 2016.

A. The Company's plan includes the Suwannee Simple Cycle Project in the summer of 2016 and the Hines Chillers Power Uprate Project by the summer of 2017. As

I mentioned above, the Company also executed a short term PPA with the Southern Company for generation capacity commencing in 2016 as part of its base generation plan with the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. Both Company projects are necessary to meet the Company's summer Reserve Margin requirement in 2016 and 2017 to deliver reliable electric service to the Company's customers.

The Suwannee Simple Cycle Project consists of two F class combustion turbine generators, two generator step-up transformers, fuel oil and demineralized water storage tanks, and related balance of plant facilities installed by June 2016 at the Company's existing Suwannee power plant site in Suwannee County, Florida. The Suwannee power plant site has existing infrastructure to support the Suwannee Simple Cycle Project. The Suwannee plant site has existing gas- and oil-fired combustion turbines, steam units and a transmission switchyard among other facilities. The new F class combustion turbine generators will be connected via a gas lateral to the Florida Gas Transmission gas pipeline and to the existing site metering and regulating station. One combustion turbine will be connected to the existing 115 kv transmission switchyard and the other combustion turbine will be connected to the existing 230 kv transmission switchyard. This existing infrastructure at the Suwannee site reduces the cost of the Suwannee Simple Cycle project. The estimated cost of the Suwannee Simple Cycle project, including the Allowance for Funds Used during Construction ("AFUDC"), is $197 million. The Suwannee Simple Cycle Project is explained in more detail in the testimony of Mr. Landseidel in this proceeding.

The Hines Chillers Power Uprate Project involves the installation of a chiller system designed to cool gas turbine inlet air to 50 degrees F and, therefore, increase the summer capacity of the combustion turbines for all four existing power blocks at the HEC. The HEC contains four natural gas-fired combined cycle units or power blocks with approximately 1,900 MW of total installed capacity. The Hines Chillers Power Uprate Project is projected to increase the total HEC power block summer output by approximately 220 MW. The Hines Chillers Power Uprate Project involves the installation of chiller modules and a large chilled water storage tank, auxiliary power system, pumps and chilled water supply and return piping, and gas turbine air inlet chiller coils including modification of the air inlet ducts on the existing power blocks. The estimated cost of the Hines Chillers Power Uprate Project, including AFUDC, is $160 million. The Hines Chillers Power Uprate Project is also explained in more detail in Mr. Landseidel's testimony in this proceeding.

Q. What impact will the addition of the Suwannee Simple Cycle and Hines Chillers Power Uprate projects have upon DEF's Reserve Margin and its ability to provide reliable service to its customers?

A. As shown in Exhibit No. ___ (BMHB-4), the addition of the Suwannee Simple Cycle Project will increase DEF's summer peak Reserve Margin to 20.4 percent in the summer of 2016. The addition of the Hines Chillers Power Uprate Project by the following summer will increase DEF's 2017 summer peak Reserve Margin to 20.7 percent. See Exhibit No. ___ (BMHB-4). The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects allow DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin.

Q. Why did DEF select the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects as the Company's generation options to meet its need in the summers of 2016 and 2017?

A. DEF's resource planning analyses show that the economics favor these projects over other Company generation options that were available to meet its near-term capacity needs in the summers of 2016 and 2017. The Company evaluated new generation, existing plant uprate projects, and existing generation life extension projects to meet this need. This evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options. Based on this evaluation, the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects were the most cost-effective generation options, based on price and non-price attributes, to meet the Company's reliability needs in the summers of 2016 and 2017. Exhibit No. ___ (BMHB-6) to my direct testimony shows the range of projects considered. I will note that at this point in the Company's evaluation, the Hines Chillers Power Uprate Project was considering chilling systems on only 3 of the 4 HEC power blocks (Power Blocks 2, 3, and 4). Further evaluation on Power Block 1 was centered around the thermal performance uprate ("TPU"). The TPU was not deemed to be economically favorable and was later dropped for consideration.

Q. What are the transmission impacts and benefits of the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects?

A. There are no additional transmission costs associated with transmission enhancements or modifications for the Hines Chillers Power Uprate Project. These are power uprates to the existing HEC power blocks which are supported by the existing transmission system connecting the HEC to DEF's system. There are limited transmission system network upgrades and costs for the Suwannee Simple Cycle Project associated with the transmission interconnection of the combustion turbines at the existing Suwannee site. These are added customer benefits from installing these projects at existing power plant sites on the Company's system compared to generation at a Greenfield site. These transmission costs and benefits are also explained in the direct testimony of Mr. Ed Scott in this proceeding.

Q. Are there environmental benefits associated with the Suwannee Simple Cycle and Hines Chillers Power Uprate projects?

A. Yes. Both projects are located at existing brown field, power plant sites. Both projects have limited to no additional environmental impact at the existing sites. As a result, the Company is able to add over 500 MW of additional summer generation capacity by the summer of 2017 with little to no additional environmental impact. These projects provide the Company with the ability to substantially increase its summer generation capacity to meet customer energy demand while maintaining the Company's compliance with current and future environmental regulations.

VI. DEF'S GENERATION RESOURCE OPTIONS ASSESSMENT .

Q. Did DEF evaluate other supply-side alternatives to meet its generation needs in the summers of 2016 and 2017?

A. Yes. The Company evaluated PPAs from other utilities and non-utility generators and the acquisition of existing, non-utility generation plants in addition to the Company's self-build generation options. These are the same options that the Company said it was going to evaluate in the 2013 Settlement Agreement approved by the Commission.

Q. Please describe DEF's efforts to solicit proposals from other supply-side providers to meet its capacity needs commencing in the summer of 2016.

A. DEF first contacted other utilities and non-utility generators with the capability of supplying some or all of the Company's near-term capacity needs in September 2012. DEF issued a solicitation for proposals for PPAs. Bids were initially received in October 2012, evaluated in November 2012, and a short list was identified and negotiations over draft PPAs commenced in January and February 2013. Changes with the Company's resource plan, in particular with the decision to retire CR3 and the potential early retirement of CR1 and CR2 in this same time period, required the Company to re-evaluate its resource plan and its generation capacity needs. This re-evaluation led the Company to identify a potential near-term generation capacity need of up to 1,150 MW in the 2013 Settlement Agreement. At the same time, however, the Company was evaluating a plan to continue commercial operation of Crystal River South in compliance with MATS through site averaging for another two years. As I explained above, the Company ultimately determined that it could operate Crystal River South until 2018 under a MATS compliance plan and it has implemented that plan with Commission approval. The implementation of this plan to continue the operation of Crystal River South to 2018 substantially reduced the Company's summer generation capacity needs prior to 2018.

DEF requested renewed proposals for PPAs and solicited interest in potential generation facility acquisitions from the potential generation suppliers who responded to the Company's earlier RFP. These potential suppliers submitted renewed bids for PPAs and generation facility acquisition offers to meet DEF's near-term generation capacity needs in September and October 2013. The Company evaluated these proposals and followed up with the bidders regarding additional information, issues, and potential supplemental offers from October 2013 through February 2014.

Q. Please explain the supply-side proposals you received.

A. The Company invited alternative proposals that offered superior customer value to the Company's self-build generation options to meet the Company's near-term capacity needs prior to 2018. We sought reliable, dispatchable, and financially sound proposals that would provide the Company generation capacity by the summer of 2016 and/or the summer of 2017. We received nine proposals for PPAs or generation facility acquisitions from seven participants. We evaluated all of these proposals by systematically following a structured, orderly evaluation process that evaluated all proposals, including the Company's self-build generation projects, on price and non-price attributes.

After initial screening, DEF evaluated both generation facility acquisition and PPA proposals from two participants. There was one system PPA proposal from another investor-owned utility, two PPA proposals from non-utility generators and three additional generation facility acquisition proposals. A confidential chart of these supply-side generation proposals that were received and evaluated by the Company to meet its capacity needs commencing in the summer of 2016 is included in Exhibit No. ___ (BMHB-7) to my direct testimony.

Q. Please describe the evaluation process.

A. The evaluation process involved an analysis of the price and non-price attributes on all the supply-side generation proposals received and the Company's self-build generation options. The proposals were first segregated into categories distinguished by the type of proposal and term to ensure a consistent and fair evaluation by categorizing and evaluating "like type" proposals. Next, the Company conducted an economic evaluation of the proposals. In this step, the proposals were screened based on the fixed and variable payments or costs and economic optimization screening analyses were performed.

The Company also preliminarily evaluated the technical feasibility and viability of the proposed acquisitions through an analysis of such factors as the operating, maintenance, and physical conditions of the plants. Other non-price attributes, including insurance, project risk, environmental impacts and compliance, and regulatory feasibility, among other factors, were also considered. This preliminary qualitative assessment was undertaken to determine if there were any proposals that were such outliers from a qualitative risk perspective that further economic evaluation was unnecessary. Upon the completion of the economic evaluation, however, a more detailed qualitative evaluation was necessary, assuming that one or more proposals were economic, before the Company could conclude that a proposal was the most cost effective generation capacity option for DEF's customers.

Finally, the Company conducted a detailed economic evaluation of each proposal compared to DEF's self-build generation alternatives, the Suwannee Simple Cycle and the Hines Chillers Power Uprates projects. This detailed economic evaluation included all costs, including transmission cost impacts, in the analysis.

Q. How did the Company perform the detailed economic evaluation?

A. The Company performed a detailed economic optimization analysis of the alternative and Company supply-side generation proposals to meet its capacity needs beginning in the summer of 2016. The purpose of the optimization analysis was to develop an optimal resource plan for each proposal for the detailed economic analysis. The optimization analyses were performed for a period of thirty years to capture all costs associated with each proposal and, in particular, to determine the type of units that make up the optimal resource plan including a proposal.

The optimization analysis was performed using the Strategist optimization model. While the economic screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of the Company's base case self-build generation plan. The optimization analysis, therefore, shows the net impact of both the proposal cost and the impact the proposal has on system capital revenue requirements and fixed and operating costs. Such an analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs. DEF integrates the resource plan optimization and fixed cost results including capital revenue requirements for generation and transmission from Strategist with the detailed production cost results from the EPM model in its detailed economic evaluations.

Q. What was the Company's base case generation plan in its detailed economic evaluation?

A. The base case was the Suwannee Simple Cycle and Hines Chillers Power Uprate projects in the summers of 2016, and 2017, respectively, followed by the other planned generation units included in the Company's 2014 TYSP. The base case or "self-build" option included chillers at only three Hines power blocks at this stage of the analysis. See Exhibit No. ___ (BMHB-2).

Q. Please explain what the Strategist optimization model is and what it does.

A. The Strategist optimization model is an industry-recognized utility system production cost model that we use to develop optimal resource plans. Strategist is a detailed, chronological production costing model that simulates each generating resource on the DEF system, both existing and future, and how each resource is used to serve the forecasted peak demand and energy requirements of DEF's customers. The objective function of the Strategist model is to minimize the cumulative present value of revenue requirements ("CPVRR") for the DEF generation system, subject to the 20 percent Reserve Margin constraint.

Thus, for each resource proposal evaluated, the Strategist model provides the optimal generation expansion plan for the 30-year study period, if the proposed resource was selected. Inputs to the model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the Company's existing generating units and purchase power agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are also included in the model. Strategist model runs develop alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative from lowest to highest cost. From an economics-only perspective, the lowest cost plan is the optimal plan.

Q. How were the results of the Strategist model optimization analysis used?

A. The results of the Strategist optimization cost analyses were used to identify optimal resource plans corresponding to each of the proposals or self-build options selected for evaluation. DEF reviewed the best plans produced by Strategist for each option and selected the plan with the lowest CPVRR for each that was feasible given constraints of transmission, construction, permitting, and other factors. The fixed cost output from Strategist was then incorporated into the financial analysis of each alternative proposal.

Q. How were the production costs associated with each alternative proposal determined?

A. After using Strategist to identify the lowest cost plan candidates, DEF uses the Planning and Risk module of the Energy Portfolio Manager ("EPM") software to further evaluate the production cost results. EPM is a detailed production cost model which evaluates the fleet dispatch in each hour over the period of the study taking into consideration both costs and projected operating constraints such as unit start times, minimum up and down times, reliability must run requirements, and projections of planned and unplanned outages. The analysis must capture these costs because each alternative proposal, due to, for example, its size, heat rate (if relevant), proposed pricing, and other factors, causes the other resources on the DEF generation system to operate in a different manner, resulting in different total system production costs. Production cost results from EPM were combined with fixed cost calculations from Strategist to calculate total 30-year production costs for each proposal and a resulting CPVRR for each proposal alternative. The cost results and CPVRR for each proposal is reviewed individually and then compared to the self build case.

Q. Were any other cost impacts included in the analysis?

A. Yes. The fixed costs of the alternatives, that is, the fixed charges of the proposals and the construction costs and fixed O&M costs of the Company's self-build generation projects, were captured in the financial analysis. The transmission construction costs to integrate each of the proposals and the Company's self-build generation projects into the transmission system were also included in the detailed economic analysis. The annual cash flow pattern of these transmission construction costs was based on typical expenditure patterns. All these costs were captured in the Strategist modeling analysis. Finally, we also evaluated the cost of imputed debt by determining the additional equity cost related to the purchased power proposals. The cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. The cost of imputed debt is a real cost associated with a PPA proposal and it therefore needs to be considered by the utility in determining the most cost-effective resource to meet its customers' reliability needs. In this case, because the term of the PPAs evaluated was five years or less, the impact of the imputed debt was found to be less than $5 million and was deemed to be not material in the results.

Q. What were the results of the detailed economic analysis?

A. In CPVRR terms, the Company's base generation plan --- the Suwannee Simple Cycle and Hines Chillers Power Uprate projects --- was found to be less expensive or more cost effective than all of the PPA proposals and all but one of the potential generation facility acquisition proposals. The Company's base generation plan was only marginally more expensive than one of the acquisition proposals, but in CPVRR terms over the 30-year study period they were nearly equivalent on an economic basis to the Company. Another potential generation facility acquisition proposal ranked third behind this generation facility acquisition and the Company's base generation plan by almost $200 million. Exhibit No. ___ (BMHB-8) to my direct testimony show the results of the initial detailed economic analysis.

Q. Did DEF consider combining one of the self-build projects with the alternative proposals?

A. Yes. DEF tested the proposals with and without the Hines Chillers. Initially, this was because some of the proposals (e.g. Acquisitions 4 and 5) did not supply sufficient MWs to meet DEF's need. During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Chillers. In each case, addition of the Hines Chillers made the project more favorable from a

CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. As a result, all of the resource plans represented in Exhibit No. __ (BMBH-8) include inlet chilling on three Hines Power Blocks.

Q. What was DEF's next step in the analysis?

A. Following review of the initial detailed economic results, DEF quantified a number of sensitivity risks around the proposals evaluated. Included in these risks were construction cost sensitivity around the Suwannee and Hines projects, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks. Exhibit No. ___ (BMHB-9) shows the results of the cost risk sensitivity analysis.

Given the range of values, DEF looked closely at two acquisition proposals as alternatives to the DEF self-build project. These were Acquisitions 1 and 2. In the case of Acquisition 1, while the option had an apparently positive CPVRR relative to the self-build option, DEF recognized that there were a number of costs that might not be fully developed. Chief among these undeveloped costs was the fact that the option had been evaluated based on its existing fuel purchase arrangements. DEF recognized that these existing arrangements provided less firm gas transportation than would be typical for a DEF facility of this type. While this might be suitable for an Independent Power Producer like Acquisition 1, further evaluation would be warranted to determine if this would provide adequate reliability for a utility asset.

In the case of Acquisition 2, DEF had made conservative assumptions regarding the cost of transmission upgrades required to deliver the power from Acquisition 2 to DEF. DEF recognized that further analysis might yield a lower cost solution. For this reason, DEF looked more closely at Acquisition 2. However, in all the acquisition cases, DEF recognized the risk that due diligence might identify differences in maintenance practices, spares stocking, or issues around unit condition, among other factors, that would add cost to these acquisition alternatives. Based on the results of these initial economic analyses, DEF concluded that there was potential for two of the acquisitions to be competitive to the self-build and that it would be prudent to proceed with an evaluation of the FERC market screen risks associated with the two acquisitions before concluding the economic analysis and proceeding to the due diligence evaluation of the potential acquisition options.

Q. What additional analyses with respect to these proposals did DEF perform?

A. Because the cost sensitivities showed that two generation facility acquisition proposals had the possibility of being close in the CPVRR analyses to the Company's base generation plan the Company took the next step in determining the feasibility of any proposed generation facility acquisition by conducting a Federal Energy Regulatory Commission ("FERC") market screen analysis.

The FERC market screen analysis is a required step in obtaining FERC approval under section 203 of the Federal Power Act ("FPA") for any public utility acquisitions of jurisdictional generation facilities. Pursuant to FPA section 203, the FERC must determine that a public utility generation facility acquisition transaction is in the public interest. To make this determination, FERC reviews the proposed transaction to assess its effect on competition in the wholesale market, wholesale rates, and regulation. The FERC market screen, or Competitive Analysis Screen, is part of this review under the Antitrust Agencies' Horizontal Merger Guidelines adopted by FERC. FERC must approve any potential generation facility acquisition by the Company before the Company can complete that acquisition.

Q. How did the Company assess the competitive impact of its proposed generation facility acquisition under the FERC market screen test?

A. The Company retained Julie Solomon with Navigant Consulting, Inc. to perform the FERC market screen analysis. Julie Solomon and Navigant are well-recognized industry experts in this area. Julie Solomon has performed the FERC market screen analysis dozens of times for potential mergers or generation facility acquisitions and she has filed testimony many times at FERC regarding the implementation and application of the FERC market screen to such transactions.

Q. What were the results of the FERC market screen analysis?

A. Both potential generation facility acquisitions that were evaluated failed the FERC Competitive Analysis Screen. Failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition transaction without mitigation efforts by the Company to eliminate the screen failures. The FERC market screen analysis and the results of that analysis are explained in more detail in the direct testimony of Julie Solomon filed on the Company's behalf in this proceeding.

Q. What did the Company do with the FERC market screen analysis results?

A. The Company decided, based on these results, that the potential generation facility acquisitions were not cost effective for the Company's customers and should not be considered further by the Company. The Company determined that the Company's base generation plan was the most cost-effective resource plan to meet customer reliability needs in the summers of 2016 and 2017.

Q. Why did the Company make this decision?

A. Both potential generation facility acquisitions failed the FERC Competitive Analysis Screen. As explained by Julie Solomon in her testimony, failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition without structural mitigation to mitigate the screen failures. There are two potential FERC-approved mitigation measures. One is for the Company to sell its own generation facilities to reduce DEF's owned or controlled generation capacity in the market. This mitigation measure makes no sense for the Company. DEF cannot sell off generation because DEF needs additional generation capacity to provide reliable electric service to its customers. This remedy is not a reasonable mitigation measure for the Company.

Another FERC-approved mitigation measure is adding transmission import capability to reduce DEF's share of the generation capacity in the market by increasing the total supply of generation in the market. This means the Company must build additional transmission facilities to expand the transmission import capability. The Company cannot rely on currently planned transmission system facility upgrades for this mitigation. The additional transmission must be net new facilities to the DEF system.

Increasing the transmission import capability by building net new transmission facilities is not a reasonable mitigation measure to eliminate the screen failures for these potential generation facility acquisitions. As explained by Julie Solomon in her direct testimony, a range of 600 MW to 800 MW of additional transmission import capacity must be added to DEF's system to mitigate the FERC screen failures for the lowest cost potential generation facility acquisition, and a minimum of 1,000 MW of additional transmission import capacity must be added to DEF's system for the other generation facility acquisition to mitigate its FERC screen failures. Based on our experience with our transmission system and the costs to add transmission facility upgrades, the transmission system facility upgrades -- and the cost of the upgrades -- to provide an additional 600 MW to 800 MW of transmission import capacity would be substantial, in the realm of hundreds of millions of dollars, and, therefore, easily far in excess of any benefits that the potential generation facility acquisitions provide DEF's customers.

The best generation facility acquisition proposal was only marginally more cost-effective on a CPVRR basis over the 20-year study period than the Company's self-build base generation plan. This marginal benefit does not warrant hundreds of millions of dollars in transmission system facility upgrades that DEF and its customers must incur to mitigate the FERC screen failures for this potential acquisition. The other potential generation facility acquisition evaluated under the FERC market screen analysis was already almost $200 million less cost-effective on a CPVRR basis than the Company's self-build generation plan, largely due to transmission system upgrades already required to incorporate the generation facility into DEF's system. The additional transmission system facility upgrades to provide a minimum of 1,000 MW of additional transmission import capability to mitigate the FERC screen failures for this potential generation facility acquisition clearly render this acquisition uneconomic for DEF and its customers.

Q. Were there any other factors that led the Company to determine that pursuit of FERC approval for these potential generation facility acquisitions was not in the best interest of the Company's customers?

A. Yes. Apart from the quantitative factors that render the potential generation facility acquisitions uneconomic, they are also qualitatively not the most cost effective options for DEF and its customers. DEF must still seek FERC approval for the generation facility acquisitions even if DEF elected to pursue mitigation, which as I explained above, is not an economically viable option for the Company. At a minimum, this means the Company must incur the cost and spend the time necessary to retain experts and develop the analyses for the case for FERC approval, and then initiate the FERC proceeding to obtain that approval, which is uncertain. The FERC proceeding, at a minimum, will take six months before the Company obtains a FERC decision. This is unacceptable to DEF and its customers. Setting aside the cost of the expert analyses and the FERC proceeding itself and the uncertainty of the outcome of that proceeding, DEF must make investment decisions now to ensure that it can reliably provide its customers with additional generation capacity in 2016.

Qualitatively too, there were other risks associated with these potential generation facility acquisitions that likely would have rendered them not cost-effective for DEF and its customers. DEF deployed a step-wise approach and evaluated these generation facility acquisitions first on the bases of CPVRR and FERC market screen analyses. Until DEF determined: (1) whether a potential acquisition was economically competitive; and (2) whether or not a potential acquisition could pass the FERC market screen, it did not make sense for DEF to complete its due diligence on these plant acquisitions, or engage in negotiations over the terms of the plant acquisitions. The condition of the plants; the environmental conditions of the plant sites; plant performance history, warranties and guarantees; financial guarantees; insurance and indemnity obligations, among other factors, would be fully evaluated only if the potential acquisition was shown to be economically competitive and capable of passing the FERC market screens. These additional qualitative factors, however, represent additional, unmitigated risk associated with the potential generation facility acquisitions that preclude the Company from determining that they are cost effective for customers.

As a result of the Company's economic and FERC market screen analyses and its evaluation of the qualitative risks associated with the proposed generation facility acquisitions, the Company determined that further review of the generation facility acquisition proposals was unnecessary. The most cost effective generation option to meet customer reliability needs prior to 2018 is the Company's self-build generation plan.

Q. Did you perform additional economic analyses following the results of the FERC market screen?

A. Yes. DEF updated the results of the most favorable remaining alternatives, adjusting the modeling case to the latest assumptions consistent with the 2014 TYSP. While this did not have a significant effect on the results, the results are shown in Exhibit __ (BMBH-10). This exhibit shows the difference in total system CPVRR associated with each supply-side generation alternative proposal compared to the Company's Base Generation Plan. DEF evaluated the highest ranking of the PPA options from the previous review and the remaining PPA-acquisition hybrid that DEF believed would pass the market screen. Both of these were significantly less cost effective than the self-build option. Prior to this point, all analyses had been done assuming that the chillers would be added only to Power Blocks 2, 3, and 4 at HEC. During this period, DEF engineering had concluded that it would be feasible to extend the chiller project to Power Block 1. The results in Exhibit __ (BMHB-10) continue to use the Suwannee project along with the three inlet chillers as the base case, but also shows the evaluation of the project with four chillers, and a resource plan in which the chillers were omitted and replaced by a third combustion turbine at Suwannee in addition to the comparison with the remaining PPA alternatives. These results support the conclusion that the most cost effective plan is the construction of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project at all four Hines power blocks.

Q. Did you perform any sensitivity analyses?

A. Yes. DEF performed sensitivity analyses of the final alternatives in our High Gas Price sensitivity case and with no CO_2 price. These cases are typically run to establish the robustness of a conclusion and to indicate how the results will vary based on variation in fuel and emission pricing, typically two of the most sensitive inputs to the production cost model. The results of these analyses are shown in Exhibit __ (BMHB-11). Comparison of the results follow generally expected patterns, favoring portfolios with higher proportions of combined cycle in the high gas case and the reverse in the no CO2 case. Since the alternatives are all gas fired, the variations between cases are relatively small. The results of these sensitivity analyses support the conclusion that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project together form the most cost effective selection for DEF's need in 2016, 2017, and beyond.

VII. THE MOST COST-EFFECTIVE GENERATION ALTERNATIVE.

Q. Is the Company's base generation plan the most cost-effective alternative for meeting the Company's reliability needs in the summers of 2016 and 2017?

A. Yes, it is. The Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Suwannee Simple Cycle and Hines Chillers Power Uprate projects as its base generation plan to meet its reliability needs by the summers of 2016 and 2017. Further, through the Company's evaluation of market proposals for alternative generation, the Company determined that the Suwannee Simple Cycle and Hines Chillers Power Uprate projects were more cost-effective, on a quantitative and qualitative basis, than any of alternative supply-side generation proposal on the market.

Q. What caused the Company's Base Generation Plan to be more cost effective than any of the other alternatives?

A. The Suwannee Simple Cycle Project is a new, state-of-the-art combustion turbine plant with higher fuel efficiency than existing combustion turbine PPAs or the acquisition of existing combustion generation facilities. As I explained above and as explained in more detail in the direct testimony of Mr. Landseidel, there are also economic benefits associated with its location at an existing Company power plant site. Further, there are no FERC market screen issues with new generation in the market. FERC is concerned with removing generation or the ability to remove generation from the market. For all these reasons, the Suwannee Simple Cycle Project proved to be a cost-effective part of the Company's base generation plan to meet its reliability needs in 2016.

The Hines Chillers Power Uprate Project is the most cost-effective generation option in every generation alternative scenario. This project adds summer generation capacity with additional combined cycle power generation. As a result, the Company obtains additional summer peaking generation at combined cycle generation efficiency and cost. The fuel efficiency and relatively low cost of the Hines Chillers Power Uprate project make it a highly cost-effective generation option to meet DEF's customer reliability needs.

VIII. CONSEQUENCES OF DELAY

Q. What will be the impact of delaying implementation of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects?

A. If the Suwannee Simple Cycle and Hines Chillers Power Uprate projects are delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2016 and 2017, respectively, in the most reliable and cost-effective manner. This would expose DEF's customers to a risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. Even without an interruption in service, without the Suwannee Simple Cycle and Hines Chillers Power Uprate projects, DEF would be forced to enter into more costly PPAs to meet this near-term reliability need. As a result, DEF's customers would be subject to higher costs to serve their reliability needs in the summer of 2016 and 2017.

IX. CONCLUSION

Q. Please summarize the benefits of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects.

A. DEF needs the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building these projects the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Company has exhausted conservation measures reasonably available to the Company and there are no reasonably available renewable energy resources or technologies to meet the Company's near-term reliability needs in the summers of 206 and 2017. The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects are the most cost-effective resources to meet customer reliability needs in this time period. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

FRCC
Florida Reliability Coordinating Council, Inc.

FRCC's Evaluation of Transmission Impact of the EPA's Mercury and Air Toxics Standard (MATS)

(Transmission Impact Study for Shutdown of Crystal River Units 1 & 2, with retirement of Crystal River Unit 3)

Performed by the FRCC TWG

Prepared by TWG	**June 3, 2013**
Accepted by MSPC	**February 4, 2014**

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Summary

The FRCC TWG, under direction of the FRCC PC, has performed a study to determine the transmission reliability impact to the FRCC Region of the EPA MATS regulation. In order to comply with the MATS regulation, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). In addition to the potential impacts of the MATS regulation, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"). The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is a significant shift in power flow patterns causing reliability concerns in areas not previously identified.

The FRCC TWG finds the following with respect to the three MATS Study deliverables:

- An extension of at least one year on the EPA's MATS compliance deadline is needed for Crystal River 1 & 2. This will alleviate significant reliability issues that would begin in the summer 2015 timeframe (without such extension), ensuring BES reliability in the FRCC Region as various transmission projects and operational mitigation procedures are implemented.

- In 2016 and 2017, significant reliability issues continue to exist with the retirement/shutdown of the Crystal River units. The TWG requests that All entities with unresolved thermal and/or voltage criteria exceptions further investigate and develop mitigation plans.

- The results of the summer 2018 analysis for the potential addition of a combined cycle facility of 1,179 MW in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved.

Purpose of Study

On December 16, 2011 the Environmental Protection Agency ("EPA") issued their Mercury and Air Toxics Standards ("MATS") regulation. The MATS regulation is designed to reduce mercury, other metals and acid gas emissions from coal- and oil-fired power plants. The MATS regulation became effective on April 16, 2012, and the initial compliance deadline is three years after the effective date, or April 16, 2015. In order to comply with the MATS rule, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). The MATS rule does offer a one year extension, to be approved by the state permitting authority (Florida Department of Environmental Protection), if reliability issues warrant an extension.

In addition to the potential impacts of the MATS rule, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"), instead of repairing it as previously planned. The unit has been off-line since 2009, and has been previously modeled in the FRCC Databank as returning to service in 2015.
As a result of these events, and their potential impact(s) to the FRCC Region, the FRCC Planning Committee ("PC") directed the Transmission Working Group ("TWG") to perform an analysis determining the impact(s) to the Bulk Electric System ("BES") and the 69 kV transmission system within the FRCC.

The primary deliverables of the evaluation were:

- Determine whether a one year extension on the EPA's MATS compliance deadline is needed to ensure reliability.

- Assess the transmission reliability impact for the 2015 through 2017 timeframe and develop potential solutions.

- Evaluate the potential reliability benefits of a new combined cycle constructed in the vicinity of the existing Crystal River site, starting operations in summer of 2018.

Case Description and Sensitivities

The initial load flow cases selected for the evaluation were the 2012 FRCC Load Flow Databank (LFDB) cases (revision 1B), which were utilized for the FRCC's 2012 Long Range Study. These cases were slightly modified to reflect known assumptions and information about the system, including long-term resource and transmission plans, as well as correcting any issues that were identified during the Long Range Study effort.

The following years and loading conditions were selected for the analysis:

- Summer - 2015, 2016 (Peak and 60%), 2017, 2018
- Winter - 2015/16, 2016 /17

The following scenarios and sensitivities were analyzed:

- Base/Study scenarios – Generation economically dispatched by respective Balancing Authority area
  - Base cases include CR 1 & 2 and CR 3 on-line and fully dispatched
  - Study cases model CR 1 & 2 and CR 3 off-line with generation replaced with DEF available reserves. Minority owners of CR 3 replaced the generation from other resources.

- Base/Study scenarios – System response at the Florida / Southern import limit
  - Timeframe - summer 2016
  - Increased Southern to Florida transfer beyond firm commitments to 3,700 MW limit with remaining resources dispatched economically

- Polk Firm sensitivity – Stress Central Florida area
  - Timeframe - winter 2016/17 and summer 2017
  - Maximize all firm resources in the Polk area
    - FPL's Manatee unit evaluated at both economic dispatch and full output

- Crystal River site combined cycle sensitivity – DEF self-build alternative
  - Model a new 1,179 MW combined cycle resource assumed in-service by the summer of 2018, this correlates to DEF's latest Ten-Year Site Plan filed at the FPSC. The location is not specified in the Ten-Year Site Plan, so based on the FRCC PC study directive the unit was placed at the Crystal River plant with the combustion turbines connected to the 230 kV bus and the steam turbine connected to the 500 kV bus, with remaining DEF generation resources economically dispatched

- Unit Out scenarios (C3-Gens analysis)
  - Bayside 2, Crystal River 4, Crystal River 5, Fort Myers 2, Sanford 5 and Stanton 2, for winter 2015 and summer 2016.

Study Methodology

The TWG analysis was performed by conducting a power flow analysis under normal and various contingency conditions using Siemens Power System Simulator for Engineering ("PSS/E") and PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software program. All system elements 69 kV and above within the FRCC region were modeled for NERC Category A, B, and selected C contingency events using steady state methods. All branches' (including transformers and ties) thermal loadings were monitored to be within System Operating Limits ("SOL"). Thermal loadings greater than 100% of a facility's applicable rating that were materially aggravated (more than 3%) when compared to the reference case or thermal overloads that did not exist in the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement. Similarly, all system busses were monitored for applicable voltage criteria, including nuclear plant interface requirements. Voltages outside of transmission owner criteria that were materially lower (more than 2%) when compared to the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement.

The TWG performed the following steps for the analysis:

- Verified that under normal operating conditions (NERC Category A criteria), all facilities remained within applicable ratings.

- Performed a "Rate C" contingency screening in order to identify any conditions that would indicate potential SOL limitations which would require pre-contingency mitigation measures. Any potential limitation required a remedy before any further analysis, in order to represent the pre-contingency condition.

- Performed a NERC Category B contingency analysis on all Base and Study cases and sensitivities using the criteria described above.

- Performed NERC Category C (C2, C5, C3 Gen and C3 Lines) event analysis on all Base and Study cases and sensitivities using the criteria described above.

General Findings

The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is generally to reduce the two power injections from (1) the north to the Tampa Bay load area, and from (2) west central Florida to the western portions of the Orlando load area. Utilizing DEF's available reserves causes a shift in the power flow patterns with issues. The specific findings for the timeframes analyzed are discussed in subsequent sections.

Deliverable 1 - Findings and potential solutions for summer 2015 & winter 2015/16

DEF's System

The summer and winter of 2015 results indicate that with CR 1 & 2, and CR 3 retirement, the flow of power from the DEF Central Florida Substation into the Greater Orlando Area is reduced significantly. That coupled with the operation of the base load units at FPL's Sanford Plant and DEF's dispatch of Debary, results in significantly increased flows in the 230 kV corridor between the generation at Debary and Sanford, and the load to the south (West Greater Orlando Area). With the previously described conditions, this path experiences significant pre-contingency loading (99% of Rate A) and post-contingency thermal overloads. Additional post-contingency thermal overloads were also observed on other elements within DEF's system, which can be resolved using various switching mitigation procedures.

A combination of the previously stated 230 kV line rebuilds, significant 69 kV and 230 kV switching (sectionalizing), and significant re-dispatch is required to resolve the corridor overloads identified above. Since this corridor is used to transfer bulk power and to serve area load, switching alternatives are limited, and clearance windows would be short, making it very unlikely that the 230 kV rebuild lines could be completed prior to April 2015. In addition, re-dispatch options are also very limited due to the absence of the three base load resources at Crystal River that results in utilizing nearly all available reserves. What remains of the identified mitigations is a less desirable option to address the identified post-contingency corridor issues: a severe combination of 69 kV and 230 kV switching (sectionalizing), combined with limited re-dispatch at Debary.

If DEF were granted an extension to delay the shutdown of CR 1 & 2, the ability to run these units will resolve these significant issues on the system through April 2016.

Seminole Electric Cooperative, Inc.'s (SECI) System

During the 2012 Long Range Study, Seminole's 69 kV transmission line located in north Sumter County was projected to experience thermal overload conditions starting in the summer of 2016 and increasing slightly through the end of the planning horizon. Seminole's plan was to reconductor the 0.3 miles of 336 ACSR with 556 ACSR prior to the start of the summer of 2016 season. However, with the loss of CR 1 & 2, the thermal overload on the respective Seminole facility begins in the summer of 2015.

Seminole's original plan was to reconductor the 0.3 miles prior to the start of the summer 2016 season; however, with the assumption that CR 1 & 2 will be shutdown by 2015, Seminole would need to accelerate the reconductor project to be complete prior to the start of the summer 2015 season. This project could remain on its current schedule per the 2012 Long Range Study if DEF was granted an extension to delay the shutdown of CR1 & 2.

Tampa Electric Company's (TEC) System
Prior to proceeding with the study analysis, the cases were assessed for potential Rate C overloads by running all contingencies (B, C2, C5 & C3 Gens) against the Rate C. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic action schemes (i.e., SPS, UVLS, etc.).

The results for the summer 2015 and winter of 2015/16 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads under contingency events that are still outstanding. Each is fully mitigated with the ability to run CR 1 & 2.

Running CR 1 & 2 at the current generation capacity, as it had been projected in the 2012 LFDB models, resolves the overloads on many of the effected TEC facilities or reduces the impact on the thermal overloads on the remaining facilities, so that switching solutions would resolve the remaining overloads.

Determination

The TWG has determined that in the summer 2015 and winter 2015/16 scenarios, with the order to comply with the MATS regulation and subsequent shutdown of Crystal River unit 1 and unit 2, in addition to the announced retirement of Crystal River 3, severe reliability issues exist. The shutdown of CR 1 & 2 will cause new overloads and increase the magnitude of known contingency overloads, many of which cannot be remedied by existing operational procedures. These post-contingency overloads will require new transmission facilities to be constructed and/or existing transmission facilities to be rebuilt or re-conductored in order to accommodate new flow patterns that have not been previously observed.

The TWG finds that a one year extension for the operation of CR units 1 & 2 is justified and necessary to maintain the integrity and the reliability of the BES within the FRCC. This extension will allow additional time to construct transmission projects to resolve many of the issues and aid in mitigating significant post-contingency overloads allowing for operational procedures to be implemented.

<u>Deliverable 2 - Transmission impacts and potential solutions in 2016 & 2017</u>

DEF's System
The results for the summer and winter of 2016 and 2017 indicate significant overloads in:

- The 230 kV tie-line between Lakeland Electric (LAK) and DEF.
- The 230 kV corridor between the generation in the area of Debary (DEF) and Sanford (FPL) and the load to the south.

By summer 2016, DEF plans to rebuild the LAK / DEF 230 kV tie-line and remove the limiting elements to resolve the worst overloads in this area, although DEF will still need to use some switching mitigation procedures for other issues downstream. DEF also plans to eliminate its most limiting elements on the addition LAK / DEF 230 kV tie-line by April 2016.

DEF is currently developing plans to have the corridor located north of Orlando in southwest Seminole County rebuilt by summer of 2016. The rebuild of these segments in this corridor will improve area conditions, but until the last rebuild project is completed along this corridor, DEF will still have to depend on some combination of 69 kV and 230 kV switching and limited re-dispatch at Debary. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues on this corridor and significantly reduce the negative impact in many other areas as well.

As observed in the summer 2015 and winter 2015/16, some additional less significant thermal overloads remain in DEF's system, but can be satisfactorily resolved using various switching mitigation procedures.

TEC's System

Similar to the summer of 2015 and winter of 2015/16 cases, the summer of 2016 & 2017 and winter of 2016/17 cases were assessed for possible Rate C overloads. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic protection system (i.e., SPS, UVLS, etc.). s:

In addition to the BES Rate C overloads, the 69 kV system is also assessed for any potential Rate C overloads that may potentially impact the BES, but not required to be resolved prior to proceeding with the study analysis.. TEC would be able to address the 69 kV overloads by choosing to uneconomically increase the Pasco Cogen generation to its maximum as pre-contingency in all the cases.

The results for the summer of 2016 & 2017 and winter of 2016/17 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads that remain outstanding. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues and significantly reduce the negative impact in other areas as well.

Determination

In the 2016 and 2017 timeframe, severe reliability issues exist with the shutdown of CR 1 & 2. The most severe issues revolve around the Polk Firm and the Unit Out scenarios (most notably, Bayside 2). In these scenarios TWG has identified Rate C overloads and numerous post-contingency overloads in the TEC area for which mitigations have not yet been developed.

<u>Deliverable 3 - Reliability impact of a new combined cycle built at Crystal River in 2018</u>

TEC's System

The results for the summer of 2018 show the elimination of the Rate B and Rate C overloads shown in the previous cases with the exception of one 230 kV transmission line under a double contingency event in the Study scenario.

The effect of installing a combined cycle facility of 1,179 MW by the summer of 2018 in the Crystal River vicinity partially alleviates the thermal overload on TEC's 230 kV transmission line to 101% and a switching solution would resolve the remaining overload.

Determination

The TWG's evaluation of the transmission impact associated with the addition of a combined cycle facility of 1,179 MW by summer 2018 in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved

Effect on future studies

This study identified several concerns without providing firm resolutions for various contingency types and system conditions. For future studies that will have to incorporate the Crystal River shutdowns and retirements, including the FRCC Long Range Study, the issues identified in this analysis will need to have adequate remedies. Additionally, any future TSR/NITS or GISR/NRIS studies will be much more complex when starting with unresolved issues. There is one GISR already underway, and it is anticipated that more will be coming in the near future.

Duke Energy Florida, Inc.
Ten-Year Site Plan

April 2014

2014-2023

Submitted to:
Florida Public Service Commission

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LIST OF REQUIRED SCHEDULES

LIST OF

TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined Cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. Duke Energy Florida, Inc.'s TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

DEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning DEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**
  This chapter provides an overview of DEF's generating resources as well as the transmission and distribution system.
- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**
  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.
- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**
  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.
- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**
  Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, Inc. (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.7 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of Saint Petersburg and Clearwater. DEF is interconnected with 22 municipal and nine rural electric cooperative systems. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 13,000 circuit miles of underground distribution cable.

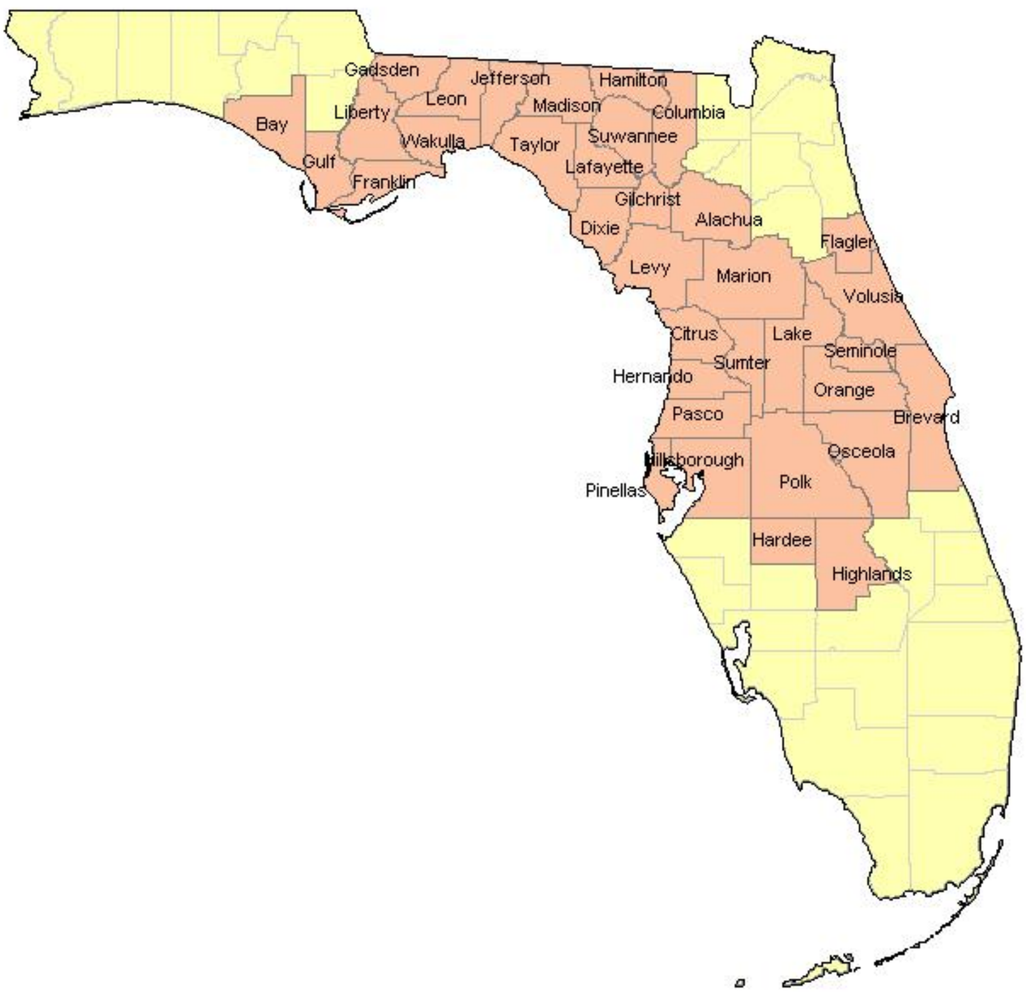
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 410,000 customers participated in the residential Energy Management program during 2013, contributing about 652 MW of winter peak-shaving capacity for use during high load periods. DEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs.

TOTAL CAPACITY RESOURCE

As of December 31, 2013, DEF had total summer capacity resources of 11,258 MW consisting of installed capacity of 9,141 MW and 2,117 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	484	506
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	490	511
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66		440,550	370	372
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69		523,800	499	503
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	710	721
SUWANNEE RIVER	1	SUWANNEE	ST	NG		PL		***	11/53	*****	34,500	28	28
SUWANNEE RIVER	2	SUWANNEE	ST	NG		PL		***	11/54	*****	37,500	29	28
SUWANNEE RIVER	3	SUWANNEE	ST	NG		PL		***	10/56	*****	75,000	71	73
												3,393	**3,463**
COMBINED-CYCLE													
BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	***	6/09		1,253,000	1,160	1,185
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	***	4/99		546,500	462	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	***	12/03		548,250	490	563
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	***	11/05		561,000	488	564
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	***	12/07		610,000	472	544
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	205	231
												3,277	**3,615**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	***	12/68	******	33,790	24	35
AVON PARK	P2	HIGHLANDS	GT	DFO		TK		***	12/68	******	33,790	24	35
BARTOW	P1, P3	PINELLAS	GT	DFO		WA		***	5/72, 6/72		111,400	86	108
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	42	57
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	49	61
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA		***	4/73		226,800	174	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK		***	12/75-4/76		401,220	310	381
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	***	10/92		345,000	247	287
DEBARY	P10	VOLUSIA	GT	DFO		TK		***	10/92		115,000	80	95
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	***	3/69, 4/69	******	67,580	45	45
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	***	12/70, 1/71	******	85,850	60	71
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK		***	5/74		340,200	286	372
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	10/93		460,000	328	379
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK		***	1/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	12/00		345,000	229	276
RIO PINAR	P1	ORANGE	GT	DFO		TK		***	11/70	******	19,290	12	15
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	***	10/80, 11/80		122,400	104	127
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK		***	10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK		***	10/70	******	38,580	20	26
TURNER	P3	VOLUSIA	GT	DFO		TK		***	8/74	******	71,200	53	77
TURNER	P4	VOLUSIA	GT	DFO		TK		***	8/74		71,200	58	78
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			1/94		43,000	46	47
												2,471	**3,031**
											TOTAL RESOURCES (MW)	**9,141**	**10,109**

** THE 143 MW SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) IS OWNED BY GEORGIA POWER COMPANY

*** APPROXIMATELY 2 TO 8 DAYS OF OIL USE TYPICALLY TARTGETED FOR ENTIRE PLANT.

***** SUWANNEE STEAM UNITS ESTIMATED TO BE SHUTDOWN BY 6/2018.

****** PEAKERS at AVON PARK, RIO PINAR, TURNER P1 & P2 ARE ESTIMATED TO BE PUT IN COLD STAND-BY OR RETIRED BY 6/2016 WITH TURNER P3 BY 12/2014 AND HIGGINS BY 6/2020.

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

DUKE ENERGY. FLORIDA

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). DEF's customer growth is expected to average 1.4 percent between 2014 and 2023, which is more than the ten-year historical average of 0.8 percent. County population growth rate projections from the University of Florida's Bureau of Economic and Business Research (BEBR) were incorporated into this projection. The severe housing crisis witnessed both nationwide and in Florida since 2007 has dampened the DEF historical ten-year growth rate significantly as total customer growth turned negative for a twenty-one month period during 2008, 2009 and 2010. Economic conditions going forward look more amenable to improved customer growth due to lower housing prices, improved housing affordability and a large retiring baby-boomer population.

Net energy for load (NEL) dropped by an average 1.2 percent per year between 2004 and 2013 due primarily to the economic recession and the weak economic recovery that followed. Sales for Resale in 2013 were only 35% of their 2004 level. Mild winter weather conditions early in 2013 and above normal rainfall over the summer also contributed to the results. The 2014 to 2023 period is expected to improve by an average growth rate of 1.5 percent per year due to expected higher population and economic growth that drives the retail jurisdiction back to more normal NEL growth rates. Going forward, projected NEL growth continues to reflect the FPSC approved DSM energy savings targets. Wholesale NEL is expected to increase by 33% over the ten year horizon.

Summer net firm demand declined an average 0.3 percent per year during the last ten years, mostly driven by a wholesale load that was nearly 50% below the average of the previous nine summers. The projected ten year period summer net firm demand growth rate of 1.6 percent is primarily driven by higher population improving net firm retail demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided:

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1	History and Forecast of Base Summer Peak Demand (MW)
3.2	History and Forecast of Base Winter Peak Demand (MW)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

DUKE ENERGY FLORIDA

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
2004	3,339,460	2.447	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,427,860	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,505,058	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,531,483	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,727	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,937	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,813	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,633,611	2.491	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,633,838	2.480	18,508	1,465,169	12,632	11,718	163,671	71,594
2014	3,700,173	2.471	18,574	1,497,280	12,405	11,617	167,106	69,519
2015	3,736,060	2.456	18,840	1,520,916	12,387	11,766	169,628	69,364
2016	3,777,512	2.446	19,179	1,544,620	12,417	12,015	172,186	69,779
2017	3,818,761	2.435	19,494	1,568,452	12,429	12,200	174,750	69,814
2018	3,861,879	2.427	19,833	1,591,324	12,463	12,297	177,209	69,393
2019	3,906,298	2.422	20,086	1,612,908	12,453	12,499	179,511	69,628
2020	3,949,461	2.417	20,351	1,634,061	12,454	12,735	181,753	70,068
2021	3,992,349	2.413	20,605	1,654,509	12,454	12,939	183,909	70,355
2022	4,033,775	2.409	20,906	1,674,417	12,486	13,239	185,998	71,178
2023	4,075,604	2.407	21,199	1,693,168	12,520	13,457	187,949	71,599

DUKE ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,176
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	3,819	2,668	1,431,409	0	26	3,341	39,282
2008	3,786	2,587	1,463,471	0	26	3,276	38,555
2009	3,285	2,487	1,320,869	0	26	3,230	37,824
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,370	1,352,743	0	25	3,159	36,616
2014	3,153	2,324	1,356,713	0	24	3,123	36,491
2015	3,173	2,307	1,375,379	0	24	3,145	36,948
2016	3,188	2,293	1,390,318	0	24	3,178	37,584
2017	3,158	2,277	1,386,913	0	23	3,198	38,073
2018	3,251	2,259	1,439,132	0	23	3,220	38,624
2019	3,503	2,241	1,563,141	0	23	3,239	39,350
2020	3,618	2,224	1,626,799	0	22	3,257	39,983
2021	3,564	2,208	1,614,130	0	22	3,274	40,404
2022	3,535	2,192	1,612,682	0	22	3,289	40,991
2023	3,490	2,176	1,603,860	0	22	3,301	41,469

DUKE ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,507	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	5,598	2,753	47,633	24,010	1,632,368
2008	6,619	2,484	47,658	24,738	1,638,935
2009	3,696	2,604	44,124	24,993	1,630,195
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,543	1,656,753
2014	936	2,374	39,801	25,904	1,692,614
2015	974	2,568	40,490	26,079	1,718,930
2016	1,024	2,490	41,098	26,233	1,745,332
2017	795	2,507	41,375	26,369	1,771,848
2018	767	2,604	41,995	26,489	1,797,281
2019	1,046	2,617	43,013	26,596	1,821,256
2020	1,270	2,745	43,998	26,689	1,844,727
2021	1,243	2,772	44,419	26,772	1,867,398
2022	1,244	2,635	44,870	26,847	1,889,454
2023	1,244	2,746	45,459	26,913	1,910,206

DUKE ENERGY FLORIDA

SCHEDULE 3.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
2004	9,583	1,071	8,512	531	331	185	39	163	110	8,224
2005	10,350	1,118	9,232	448	310	203	38	166	110	9,074
2006	10,147	1,257	8,890	329	307	222	37	170	66	9,016
2007	10,931	1,544	9,387	334	291	239	45	177	110	9,735
2008	10,592	1,512	9,080	500	284	255	66	192	110	9,186
2009	10,853	1,618	9,235	262	291	271	84	211	110	9,624
2010	10,238	1272	8,966	271	304	296	96	232	110	8,929
2011	9,968	934	9,034	227	317	327	97	255	110	8,636
2012	9,783	1080	8,703	262	326	355	100	278	124	8,338
2013	9,581	581	9,000	334	332	384	101	297	124	8,008
2014	10,359	804	9,555	254	337	411	105	308	132	8,812
2015	10,631	806	9,825	256	342	434	110	316	132	9,042
2016	10,775	658	10,117	255	347	455	114	323	132	9,149
2017	10,998	587	10,411	256	383	473	118	330	132	9,307
2018	11,169	587	10,582	263	388	488	122	336	132	9,440
2019	11,620	837	10,783	310	393	503	127	342	132	9,813
2020	11,795	837	10,958	332	398	520	131	346	132	9,935
2021	11,842	737	11,104	333	403	536	135	351	132	9,952
2022	11,985	738	11,247	333	408	550	139	355	132	10,067
2023	12,118	738	11,380	333	413	564	143	359	132	10,173

Historical Values (2004 - 2013):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) =Customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2014 - 2023):
Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
2003/04	9,323	1,167	8,156	498	788	342	26	123	262	7,284
2004/05	10,830	1,600	9,230	575	779	371	26	123	283	8,673
2005/06	10,698	1,467	9,231	298	762	413	26	124	239	8,835
2006/07	9,896	1,576	8,320	304	671	453	26	126	262	8,055
2007/08	10,964	1,828	9,136	234	763	487	34	132	278	9,036
2008/09	12,092	2,229	9,863	268	759	522	71	147	291	10,034
2009/10	13,698	2,189	11,509	246	651	567	80	162	322	11,670
2010/11	11,347	1,625	9,722	271	661	633	94	179	214	9,295
2011/12	9,715	905	8,810	186	639	681	96	202	206	7,706
2012/13	9,105	831	8,274	248	652	744	97	219	193	6,952
2013/14	11,126	895	10,231	237	661	796	101	233	228	8,870
2014/15	11,476	1,376	10,099	238	670	845	105	241	243	9,133
2015/16	11,779	1,378	10,401	238	679	887	110	249	246	9,371
2016/17	11,788	1,088	10,700	238	706	927	114	256	249	9,298
2017/18	12,093	1,088	11,005	245	715	956	118	263	252	9,544
2018/19	12,281	1,088	11,193	288	724	984	122	269	254	9,639
2019/20	12,690	1,338	11,351	309	733	1,018	127	275	256	9,972
2020/21	12,827	1,338	11,489	310	742	1,049	131	278	257	10,059
2021/22	12,958	1,339	11,619	310	751	1,079	135	281	258	10,143
2022/23	13,083	1,339	11,745	310	760	1,106	139	285	259	10,224

Historical Values (2004 - 2013):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2014 - 2023):
Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
2004	46,834	426	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,475	455	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,399	484	365	509	39,432	4,220	2,389	46,041	52.1
2007	49,310	511	387	779	39,282	5,598	2,753	47,633	52.3
2008	49,208	543	442	565	38,556	6,619	2,483	47,658	53.1
2009	45,978	583	492	779	37,824	3,696	2,604	44,124	44.5
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.0
2013	43,150	778	736	864	36,616	1,488	2,668	40,772	53.0
2014	42,249	821	763	864	36,491	936	2,374	39,801	51.2
2015	43,047	857	787	913	36,948	974	2,568	40,490	50.6
2016	43,714	890	810	916	37,584	1,024	2,490	41,098	49.9
2017	44,037	918	831	913	38,073	795	2,507	41,375	50.8
2018	44,702	944	850	913	38,624	767	2,604	41,995	50.2
2019	45,763	969	868	913	39,350	1,046	2,617	43,013	50.9
2020	46,797	996	887	916	39,983	1,270	2,745	43,998	50.2
2021	47,258	1,021	905	913	40,404	1,243	2,772	44,419	50.4
2022	47,749	1,044	922	913	40,991	1,244	2,635	44,870	50.5
2023	48,377	1,067	938	913	41,469	1,244	2,746	45,459	50.8

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration.

** Load Factors for historical years are calculated using the actual winter peak demand except the 2004, 2007, 2012 and 2013 historical load factors which are based on the actual summer peak demand which became the annual peaks for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

DUKE ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2013		FORECAST 2014		FORECAST 2015	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	5,877	2,881	9,973	3,166	10,257	3,213
FEBRUARY	8,032	2,746	8,454	2,713	9,127	2,766
MARCH	7,856	3,031	7,479	2,879	8,188	2,936
APRIL	7,153	3,166	7,537	2,954	7,781	3,008
MAY	7,863	3,460	8,467	3,560	8,694	3,616
JUNE	8,524	3,965	9,021	3,749	9,246	3,810
JULY	8,352	3,983	9,327	3,953	9,562	4,012
AUGUST	8,776	4,283	9,509	3,993	9,750	4,058
SEPTEMBER	8,446	3,861	8,778	3,728	8,984	3,790
OCTOBER	7,645	3,517	8,192	3,330	8,472	3,390
NOVEMBER	6,418	2,912	6,697	2,738	6,902	2,804
DECEMBER	5,826	2,967	8,764	3,038	8,879	3,087
TOTAL		40,772		39,801		40,490

NOTE: Recorded Net Peak demands and System requirements include off-system wholesale contracts.

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. DEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one fuel source. Near term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth and natural gas generation costs reflect relatively attractive natural gas commodity pricing.

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,543	4,792	4,521	5,099	4,709	5,443	4,951	4,431	3,314	3,253	2,863	3,230
(3)	RESIDUAL	TOTAL	1,000 BBL	89	251	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	89	251	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	160	132	128	145	159	116	117	66	96	69	93	166
(9)		STEAM	1,000 BBL	60	55	61	61	54	49	31	12	31	33	45	39
(10)		CC	1,000 BBL	1	8	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	99	69	66	84	105	67	86	54	64	36	48	126
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	187,251	177,196	185,946	183,135	188,841	185,881	196,042	211,855	232,439	245,117	258,700	256,669
(14)		STEAM	1,000 MCF	26,837	23,404	31,406	37,531	36,652	26,744	25,644	26,128	23,891	24,146	24,876	28,004
(15)		CC	1,000 MCF	155,717	150,875	148,761	138,981	142,519	149,678	160,865	177,949	200,579	213,835	226,668	219,394
(16)		CT	1,000 MCF	4,697	2,917	5,779	6,623	9,669	9,459	9,533	7,778	7,969	7,135	7,156	9,271
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	0	0	12,711	12,734	18,515	14,152	13,659	13,607	14,812	5,519	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	0	0	7,403	8,894	10,318	6,071	6,028	5,518	5,312	4,373	4,938	7,123
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	0	0	221	225	105	0	0	0	0	0	0	0

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,558	1,409	709	854	989	578	577	529	495	408	457	687
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,003	10,577	9,816	11,072	10,078	11,776	10,826	9,272	6,772	6,617	5,802	6,585
(4)	RESIDUAL	TOTAL	GWh	46	127	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	46	127	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	104	93	27	35	43	27	35	23	27	16	21	57
(10)		STEAM	GWh	63	58	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	1	7	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	39	28	27	35	43	27	35	23	27	16	21	57
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,997	23,061	24,337	23,621	24,374	24,194	25,818	28,468	31,855	33,840	35,846	35,370
(15)		STEAM	GWh	2,175	1,951	2,738	3,349	3,264	2,235	2,159	2,240	2,006	2,038	2,136	2,430
(16)		CC	GWh	21,469	20,893	21,037	19,641	20,183	21,038	22,732	25,465	29,061	31,087	32,998	32,032
(17)		CT	GWh	353	217	562	631	927	921	927	763	788	715	711	908
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,767	2,886	1,421	1,444	1,529	1,527	1,533	1,526	1,506	1,507	1,498	1,505
	RENEWABLES		GWh	1,183	1,132	1,301	1,260	1,277	1,279	1,285	1,280	1,254	1,253	1,245	1,256
	IMPORT FROM OUT OF STATE		GWh	1,559	1,546	2,191	2,203	2,809	1,995	1,921	1,915	2,089	777	0	0
	EXPORT TO OUT OF STATE		GWh	-4	-59	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	41,213	40,772	39,801	40,490	41,098	41,375	41,995	43,013	43,998	44,419	44,870	45,459

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		%	3.8%	3.5%	1.8%	2.1%	2.4%	1.4%	1.4%	1.2%	1.1%	0.9%	1.0%	1.5%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	24.3%	25.9%	24.7%	27.3%	24.5%	28.5%	25.8%	21.6%	15.4%	14.9%	12.9%	14.5%
(4)	RESIDUAL	TOTAL	%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(10)		STEAM	%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	58.2%	56.6%	61.1%	58.3%	59.3%	58.5%	61.5%	66.2%	72.4%	76.2%	79.9%	77.8%
(15)		STEAM	%	5.3%	4.8%	6.9%	8.3%	7.9%	5.4%	5.1%	5.2%	4.6%	4.6%	4.8%	5.3%
(16)		CC	%	52.1%	51.2%	52.9%	48.5%	49.1%	50.8%	54.1%	59.2%	66.1%	70.0%	73.5%	70.5%
(17)		CT	%	0.9%	0.5%	1.4%	1.6%	2.3%	2.2%	2.2%	1.8%	1.8%	1.6%	1.6%	2.0%
(18)	OTHER 2/														
	QF PURCHASES		%	6.7%	7.1%	3.6%	3.6%	3.7%	3.7%	3.6%	3.5%	3.4%	3.4%	3.3%	3.3%
	RENEWABLES		%	2.9%	2.8%	3.3%	3.1%	3.1%	3.1%	3.1%	3.0%	2.8%	2.8%	2.8%	2.8%
	IMPORT FROM OUT OF STATE		%	3.8%	3.8%	5.5%	5.4%	6.8%	4.8%	4.6%	4.5%	4.7%	1.7%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

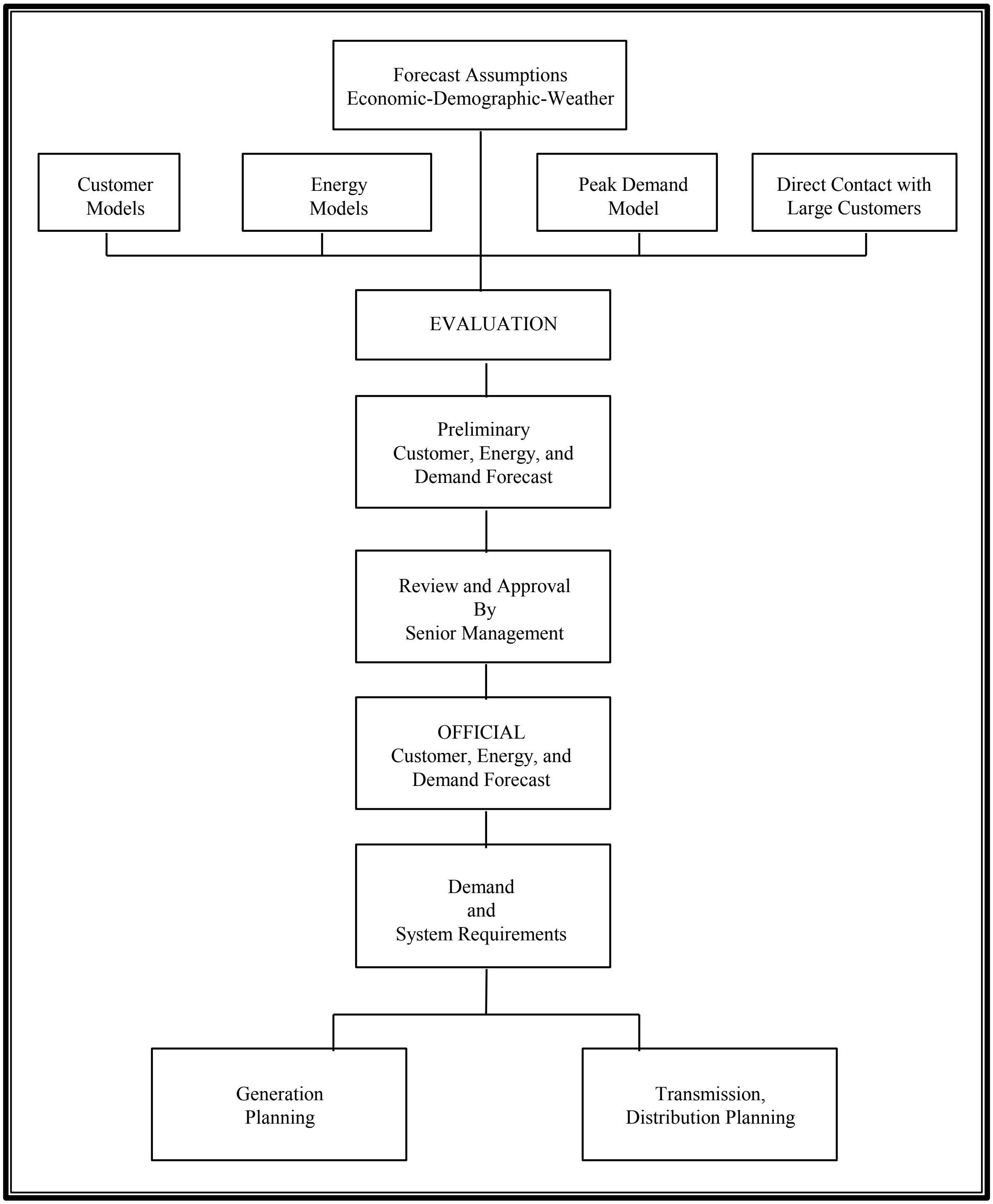
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 10-year average of conditions at the St Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 10-year average of the billing cycle weighted monthly heating and cooling degree-days. The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the ten year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day values begin to accumulate. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the same three weather stations. The remaining months of the year may use less than 30 years if an historical monthly peak occurred during an unexpected time of day due to unusual weather.

2. Historical population, household and average household size estimates by Florida county produced by the BEBR at the University of Florida as published in "Florida Population Studies", Bulletin No. 65 (March 2013). The projected change in Florida average household size from Moody's Analytics provided the basis for the 29 county household projection used in the development of the customer forecast. National and Florida economic projections produced by Moody's Analytics in their July 2013 forecast provided the basis for development of the DEF customer and energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Three major customers accounted for exactly 33 percent of the industrial class MWh sales in 2013. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward,

global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. The DEF forecast calls for an increase in annual electric energy consumption due to a new mine opening later in this decade. A risk to this projection lies in the price of energy, which is a major cost of both mining and producing phosphoric fertilizers. Fuel charges embedded in DEF's rates versus competitors' rates play a role as to where a mining customer directs output from self-owned generation facilities. This can reduce DEF industrial sales.

4. DEF supplies load and energy service to wholesale customers on a "full" and "partial" requirement basis. Full requirements (FR) customers demand and energy are assumed to grow at a rate that approximates their historical trend. However, the impact of the current recession has reduced short term growth expectations. Contracts for this service include the cities of Chattahoochee, Mt. Dora and Williston. Partial requirements (PR) customers load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Reedy Creek Improvement District (RCID), Seminole Electric Cooperative, Inc. (SECI), and the cities of New Smyrna Beach and Homestead.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently offered DSM programs.

7. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. This projection incorporates an increase of over 15 MW of self-service generation in 2013 from two customers. DEF will supply the supplemental load of self-service cogeneration customers. While DEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place. FR customers are typically assumed to renew their contracts with DEF except those who have termination provisions and have given their notice to terminate. PR contracts are typically projected to terminate as terms reach their expiration date.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2013 as the nation waited for stronger signs of growth. Most economic indicators pointed to better days ahead but Washington policy-makers continued to debate pro-growth versus deficit reduction strategies which prolonged uncertainty for consumers, employers and capital investment decision-makers. Consumer confidence and sentiment surveys improved, reflecting the lower unemployment rate and record setting stock market indexes. In Florida, these trends were tempered by continued high foreclosure rates and an expected sixth straight year of lower Statewide median household real income from its 2007 peak.

The DEF forecast incorporates the economic assumptions implied in the Moody's Analytics U.S. and Florida forecasts with some minor tempering to its short term optimism. This view suggests that a de-leveraging American consumer will begin to spend again, feeling more secure about the outlook. The newfound abundance of American energy supplies, creating additional job growth and low natural gas prices, is expected to improve the country's competitive advantage in several manufacturing sectors. An improved manufacturing sector is well displayed in many parts across the U.S. The domestic economic picture will, however, continue to feel the drag from a weak Euro-Zone and other emerging economies. This will be reflected in lower short term growth from what has been a surprising source of U.S. GDP growth: American exports.

The debt bubble that set the conditions for the Great Recession and the lingering effects of the recession have created many economic imbalances that many now believe will result in a longer time to return to equilibrium than the ordinary recession. Signs of optimism do exist, however.

DEF customer growth increased by more than 20,000 in December 2013 from December 2012. The anticipated influx of retiring baby-boomers may just be starting to be reflected in the data.

Energy prices are expected to remain in a tight range through the forecast due to increased supplies of both fossil fuels and renewables. The potential for a carbon tax or other monetization of carbon restrictions remains on the horizon in the 2020 period and is incorporated into this forecast's electric price projection. No disruption in global supplies of energy or new environmental findings over the safety of extracting fossil fuels are expected in the forecast horizon.

Also incorporated in this energy forecast is a projection of customer-owned solar photovoltaic generation and electric vehicle ownership. The net energy impact of both are expected to result in only marginal impacts to the forecasted energy growth.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, interruptible service and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Analytics and the University of Florida's BEBR. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. The incorporation of residential and commercial "end-use" energy have been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company's Market Research department and the Energy Information Agency (EIA), along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an easier explanation of usage levels and changes in weather-sensitivity over time. The "bundling" of 19 residential appliances into "heating", "cooling" and "other" end uses form the basis of equipment-oriented drivers that are interacted with the typical exogenous factors as real median household income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with households within DEF's 29 county service area. County level population projections for counties in which DEF serves residential customers are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. As in the residential sector, these variables are interacted with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation

- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment interacted with the Florida industrial production index, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out, start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon.

Street Lighting

Electricity sales to the street and highway lighting class have remained flat for years but have declined of late. A continued decline is expected as improvements in lighting efficiency are projected. The number of accounts, which has dropped by more than one-third since 1995 due to most transferring to public authority ownership, is expected to decline further before leveling off in the intermediate term. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow within the size of the service area. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e. public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use in the billing months of January, July, and August. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or sales for resale, customer of DEF contracting to purchase base, intermediate and peaking stratified load over varying time periods over the forecast horizon. The municipal sales for resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Three customers in this class, Chattahoochee, Mt. Dora, and Williston, are municipalities whose full energy requirements are supplied by DEF. Energy projections for full requirement customers grow at a rate that approximates their historical trend with additional information coming from the respective city officials. DEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, and another power provider, RCID. In each case, these customers contract with DEF for a specific level and type of stratified capacity needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load and expected fuel prices.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF’s coincident system peak is separated into five major components. These components consist of potential firm retail load, interruptible and curtailable tariff non-firm load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

Potential firm retail load refers to projections of DEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's firm retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in load control reductions. Seasonal peaks are projected using the historical seasonal peak hour regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected. Energy conservation and direct load control estimates are consistent with DEF's DSM goals that have been established by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of retail monthly peak demand figures.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of monthly demands. The Full Requirement municipal demand forecast is estimated for individual cities using historically trended growth rates adjusted for current economic conditions.

DEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon as it has historically. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from DEF's large industrial accounts by account executives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

CONSERVATION

On August 16, 2011, the PSC issued Order No. PSC-11-0347-PAA-EG, Modifying and Approving the Demand Side Management Plan of DEF (formerly known as Progress Energy Florida, Inc.). In this Order, the FPSC modified DEF's DSM Plan to consist of those existing programs in effect as of the date of the Order.

The following tables show the 2010 through 2013 achievements from DEF's existing set of DSM programs.

Residential Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	43	85	58
2011	82	160	110
2012	115	229	156
2013	140	274	195

Commercial Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	36	32	66
2011	65	61	132
2012	92	81	196
2013	118	101	237

Total Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	79	116	124
2011	148	221	242
2012	208	310	352
2013	258	375	432

DEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs that will continue to be offered through 2014. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. A brief description of each of the currently offered DSM programs is provided below.

In 2012, DEF received administrative approval of revisions to four programs as a result of changes to the Florida Building Code: Home Energy Improvement, Residential New Construction, Business New Construction and Better Business. The Building Code changes resulted in increased minimum efficiency levels which resulted in an increase in the baseline efficiency level from which DEF provides incentives. The revisions to the four programs are incorporated in the descriptions below.

In 2013, the increased efficiency standards impacted participation in DEF's approved DSM programs as measures that previously were eligible for incentives became required standards ineligible for incentives. The higher performance requirements established by the changes to the Florida Building Code, along with the state and federal minimum efficiency standards for residential appliances and commercial equipment, resulted in a reduction of demand and energy savings from DEF's DSM programs. As the U.S. Department of Energy (DOE) continues the implementation of increased energy efficiency standards for residential and commercial end-uses, the amount of demand and energy savings captured by DEF's DSM programs will decrease. As DEF continues its planning process in the ongoing DSM goals docket, the impacts of future implementation of state building code and federal appliance standards will be incorporated into its DSM goal proposals.

DEF's CURRENTLY APPROVED DSM PROGRAMS:

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides residential customers with an analysis of their current energy use and provides recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers DEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-Completed Mail-In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit – a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III); and Type 7: Student Mail In Audit - a student-completed audit. The Home Energy Check program serves as the foundation of the Home Energy Improvement program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement

The Home Energy Improvement Program is the umbrella program that serves to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps. Additional measures within this program include spray-in wall insulation, central AC 14 Seasonal Energy Efficiency Ratio (SEER) non-electric heat, and proper sizing of high efficiency Heating, Ventilation and Air Conditioning (HVAC) systems, HVAC commissioning, reflective roof coating for manufactured homes, reflective roof for single-family homes, window film or screen, and replacement windows.

Residential New Construction

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the U.S. Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. Additional measures within the Residential New Construction program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler, and energy recovery ventilation.

Low Income Weatherization Assistance

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver

This program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead, refrigerator coil brush, HVAC filters, and weatherization measures (i.e. weather stripping, door sweeps, etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

Residential Energy Management (EnergyWise)

This program allows DEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio-controlled switches installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh per month.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of a free walk-through audit and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues as well as incentives on efficiency measures. The Better Business program promotes energy efficient HVAC, building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation, and Energy Star cool roof coating products), demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the State of Florida energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives are available for high efficiency HVAC equipment, energy recovery ventilation, Energy Star cool roof coating products, demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal energy storage and window film or screen.

Innovation Incentive

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for DEF customers. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak demand and/or energy, but are not addressed by other programs. Energy efficiency opportunities are identified by DEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to DEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces DEF's demand during peak or emergency conditions. As described in DEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent structures and utilized for the following purposes: 1) water heater(s), 2) central electric heating system(s), 3) central electric cooling system(s), and or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation

This demand control program reduces DEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability of at least 50 kW, and are willing to reduce their demand when DEF deems it necessary. Customers participating in the Standby Generation program receive a monthly credit on their electric bills according to their demonstrated ability to reduce demand at DEF's request.

Interruptible Service

This direct load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. DEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for the ability to interrupt load, customers participating in the Interruptible Service program receive a monthly credit applied to their electric bills.

Curtailable Service

This load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001(5)(f), Florida Administration Code). In accordance with the rule, the Technology Development program facilitates the research of innovative technologies and continued advances within the energy industry. DEF will undertake certain development, educational and demonstration projects that have potential to become DSM programs. Examples of such projects include the evaluation of Premise Area Networks that provide an increase in customer awareness of efficient energy usage while advancing demand response capabilities. Additional projects have included the evaluation of off-peak generation with energy storage for on-peak demand consumption, small-scale wind and smart charging for plug-in hybrid electric vehicles. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

DEMAND-SIDE RENEWABLE PORTFOLIO

Solar Water Heating for the Low-income Residential Customers Pilot

This pilot program is designed to assist low-income families with energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. DEF collaborates with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system is provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This pilot program encourages residential customers to install new solar thermal water heating systems on their residence with the requirement for customers to participate in our residential Energy Management program (EnergyWise). Participants receive a one-time $550 rebate designed to reduce the upfront cost of the renewable energy system, plus a monthly bill credit associated with their participation in the residential Energy Management program.

Residential Solar Photovoltaic Pilot

This pilot encourages residential customers to install new solar photovoltaic (PV) systems on their home. A DEF audit is required prior to system installation to qualify for this rebate. Participating customers will receive a one-time rebate of up to $20,000 to reduce the initial investment required to install a qualified renewable solar PV system. The rebate is based on the wattage of the PV (DC) power rating.

Commercial Solar Photovoltaic Pilot

This pilot encourages commercial customers to install new solar PV systems on their facilities. A DEF energy audit is required prior to system installation to qualify for this rebate. The program provides participating commercial customers with a tiered rebate to reduce the initial investment in a qualified solar PV system. The rebate is based on the PV (DC) power rating of the unit installed. The total incentives per participant will be limited to $130,000, based on a maximum installation of 100 kW.

Photovoltaic For Schools Pilot

This pilot is designed to assist schools with energy costs while promoting energy education. This program provides participating public schools with new solar photovoltaic systems at no cost to the school. The primary goals of the program are to:

- Eliminate the initial investment required to install a solar PV system
- Increase renewable energy generation on DEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in DEF communities and schools

The program will be limited to an annual target of one system with a rating up to 100 KW installed on a post secondary public school and ten 10 KW systems with battery backup option installed on public K-12 schools, preferably serving as emergency shelters.

Research and Demonstration Pilot

The purpose of this pilot program is to research technology and establish Research and Design initiatives to support the development of renewable energy pilot programs. Demonstration projects will provide real-world field testing to assist in the development of these initiatives. The program will be limited to a maximum annual expenditure equal to 5% of the total Demand-Side Renewable Portfolio annual expenditures.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2013 DEF had a summer total capacity resource of 11,258 MW (see Table 3.1). This capacity resource includes fossil steam (3,393 MW), combined-cycle plants (3,277 MW), combustion turbines (2,471 MW; 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (413 MW), independent power purchases (1,114 MW), and non-utility purchased power (590 MW). Table 3.2 presents DEF's firm capacity contracts with Renewable and Cogeneration Facilities.

Demand-Side Programs

Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. DEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with DEF. In its planning process, DEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site. DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan. DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews. DEF expects to file formal petitions regarding resource selections resulting from these evaluations during 2014.

The promulgation of the Mercury and Air Toxics Standards (MATS) by EPA in April of 2012 presents new environmental requirements for the DEF units at Anclote, Suwannee and Crystal River.

- The three steam units at Suwannee are capable of operation on both natural gas and residual oil. These units will be able to comply with the MATS rule by ceasing operation on residual oil prior to the April 2015 compliance date. Residual oil was removed from the site in 2013.
- DEF is continuing to execute projects at the Anclote facility to convert the two residual oil fired units there to 100% firing on natural gas. These environmental control upgrades are expected to enable these two units to operate in compliance with the requirements of the MATS. Following completion of the project in 2014, DEF will conduct final tests to confirm performance levels.
- Crystal River Units 1 and 2 are not capable of meeting the emissions requirements for MATS in their current configuration and using the current fuel. In addition, under the terms of the revised air permit, in accordance with the State Implementation Plan for compliance with the requirements of the Clean Air Visible Haze Rule, these units are required to cease coal fired operation by the end of 2020 unless scrubbers are installed prior to the end of 2018.
- DEF has received a one year extension of the deadline to comply with MATS for Crystal River Units 1 and 2 from the Florida Department of Environmental Protection. This extension was granted to provide DEF sufficient time to complete projects necessary to

enable interim operation of those units in compliance with MATS during the 2016 – 2020 period.

- DEF anticipates burning MATS compliance coals in Crystal River Units 1 and 2 beginning no later than April 2016. Although specific dates have not been finalized, DEF anticipates retiring the Crystal River Units 1 and 2 in 2018 in coordination with the 2018 Citrus Combined Cycle operations.
- Additional details regarding DEF's compliance strategies in response to the MATS rule are provided in DEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 140007-EI.

DEF continues to look ahead to the projected retirements of several of the older units in the fleet, particularly combustion turbines at Higgins, Avon Park, Turner and Rio Pinar as well as the three steam units at Suwannee. Turner Unit P3 is projected to retire at the end of 2014. The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. There are many factors which may impact these retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2014 through 2023. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan. Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with DEF Bulk Electric System (BES) are shown in Schedule 10.

TABLE 3.1

DUKE ENERGY FLORIDA

**TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS**

AS OF DECEMBER 31, 2013

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Fossil Steam			
Crystal River	4	2,291	
Anclote	2	974	
Suwannee River	3	128	
Total Fossil Steam	9	3,393	
Combined Cycle			
Bartow	1	1,160	
Hines Energy Complex	4	1,912	
Tiger Bay	1	205	
Total Combined cycle	6	3,277	
Combustion Turbine			
DeBary	10	637	
Intercession City	14	986	*(1)*
Bayboro	4	174	
Bartow	4	177	
Suwannee	3	155	
Turner	4	131	
Higgins	4	105	
Avon Park	2	48	
University of Florida	1	46	
Rio Pinar	1	12	
Total Combustion Turbine	47	2,471	
Total Units	**62**		
Total Net Generating Capability		**9,141**	

(1) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Firm Qualifying Facility Contracts	11	590	
Investor Owned Utilities	2	413	
Independent Power Producers	2	1,114	
TOTAL CAPACITY RESOURCES		**11,258**	

TABLE 3.2

DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS

AS OF DECEMBER 31, 2013

Facility Name	Firm Capacity (MW)
El Dorado*	114.2
Lake County Resource Recovery **	12.8
LFC Jefferson*	8.5
LFC Madison*	8.5
Mulberry	115
Orange Cogen (CFR-Biogen)	74
Orlando Cogen ***	79.2
Pasco County Resource Recovery	23
Pinellas County Resource Recovery 1	40
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Florida Power Development	60
TOTAL	**589.6**

* El Dorado, LFC Jefferson and LFC Madison expire 12/31/13.

** Lake County Resource Recovery expires 6/1/2014

*** Orlando Cogen increases contract capacity by 35.8MW to 115MW on 1/1/2014

DUKE ENERGY FLORIDA

SCHEDULE 7.1
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL[a] INSTALLED CAPACITY	FIRM[b] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[c]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2014	9,015	1,831	0	177	11,024	8,812	2,211	25%	0	2,211	25%
2015	8,982	1,831	0	177	10,991	9,042	1,949	22%	0	1,949	22%
2016	9,089	1,873	0	177	11,140	9,149	1,991	22%	0	1,991	22%
2017	9,254	1,873	0	177	11,305	9,307	1,998	21%	0	1,998	21%
2018	9,206	1,923	0	177	11,307	9,439	1,868	20%	0	1,868	20%
2019	10,026	1,873	0	177	12,077	9,813	2,264	23%	0	2,264	23%
2020	9,921	1,873	0	177	11,972	9,935	2,037	21%	0	2,037	21%
2021	10,714	1,448	0	177	12,340	9,952	2,388	24%	0	2,388	24%
2022	10,714	1,448	0	177	12,340	10,067	2,273	23%	0	2,273	23%
2023	10,714	1,448	0	177	12,340	10,173	2,167	21%	0	2,167	21%

Notes:

a. Total Installed Capacity does not include the 143 MW to Southern Company from Intercession City, P11.

b. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

c. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 7.2
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2013/14	10,109	1,916	0	190	12,215	8,870	3,345	38%	0	3,345	38%
2014/15	10,062	1,916	0	177	12,155	9,133	3,022	33%	0	3,022	33%
2015/16	10,062	1,946	0	177	12,185	9,370	2,815	30%	0	2,815	30%
2016/17	10,194	1,958	0	177	12,330	9,298	3,032	33%	0	3,032	33%
2017/18	10,194	1,958	0	177	12,330	9,544	2,786	29%	0	2,786	29%
2018/19	11,142	1,958	0	177	13,278	9,639	3,639	38%	0	3,639	38%
2019/20	11,142	1,958	0	177	13,278	9,971	3,306	33%	0	3,306	33%
2020/21	11,026	1,958	0	177	13,162	10,059	3,103	31%	0	3,103	31%
2021/22	11,892	1,533	0	177	13,603	10,144	3,459	34%	0	3,459	34%
2022/23	11,892	1,533	0	177	13,603	10,225	3,378	33%	0	3,378	33%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2014 THROUGH DECEMBER 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY[a]			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
ANCLOTE	1	PASCO	ST	NG		PL			5/2014			17	11	FC/A	(1) and (2)
ANCLOTE	2	PASCO	ST	NG		PL			12/2014			20	19	FC/A	(1) and (2)
TURNER	3	VOLUSIA	GT							12/2014		(53)	(77)	RT	(2)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		4/2016			(50)	(52)	FC	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		4/2016			(79)	(80)	FC	(2)
TURNER	P 1-2	VOLUSIA	GT							6/2016		(20)	(26)	RT	(2)
AVON PARK	P 1-2	HIGHLANDS	GT							6/2016		(48)	(70)	RT	(2)
RIO PINAR	P1	ORANGE	GT							6/2016		(12)	(15)	RT	(2)
SUWANNEE RIVER	P 4-5	SUWANNEE	GT					12/2014	06/2016			316	375	P	(2) and (3)
HINES	2-4	POLK	CC	NG		PL			3/2017			165	0	RP	(2) and (3)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/1966	4/2018		(320)	(320)	RT	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/1969	4/2018		(420)	(423)	RT	(2)
SUWANNEE RIVER	1-3	SUWANNEE	ST							6/2018		(129)	(131)	RT	(2)
CITRUS	1	CITRUS	CC					11/2015	05/2018			1640	1820	P	(2), (3), and (4)
HIGGINS	P 1-4	PINELLAS	GT							6/2020		(105)	(116)	RT	(2)
UNKNOWN	1	UNKNOWN	CC					01/2018	06/2021			793	866	P	(2)

a. See page v. for Code Legend of Future Generating Unit Status.
b. NOTES
(1) Capability was reduced after gas conversion due to FD fan limitations. FD Fan replacement increases the capability to what it was before the Gas Conversion.
(2) Planned, Prospective, or Committed project.
(3) DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews
(4) Approximately 50% of plant capacity is planned in service 5/2018 with the balance in service 11/2018

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:		**Suwannee CTs (Units 4 and 5)**	
(2)	Capacity			
	a. Summer:		316	
	b. Winter:		375	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		12/2014	
	b. Commercial in-service date:		6/2016	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low NOx Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		N/A	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.85	%
	b. Forced Outage Factor (FOF):		2.05	%
	c. Equivalent Availability Factor (EAF):		94.18	%
	d. Resulting Capacity Factor (%):		9.3	%
	e. Average Net Operating Heat Rate (ANOHR):		10,197	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		661.57	
	c. Direct Construction Cost ($/kW):	($2014)	605.36	
	d. AFUDC Amount ($/kW):		45.97	
	e. Escalation ($/kW):		10.23	
	f. Fixed O&M ($/kW-yr):	($2014)	3.86	
	g. Variable O&M ($/MWh):	($2014)	3.26	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:		**Citrus Combined Cycle**	
(2)	Capacity			
	a. Summer:		1640	
	b. Winter:		1820	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		11/2015	
	b. Commercial in-service date:		5/2018 - 11/2018	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst	
(7)	Cooling Method:		Cooling Tower	
(8)	Total Site Area:		410	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		8.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		90.16	%
	d. Resulting Capacity Factor (%):		76.6	%
	e. Average Net Operating Heat Rate (ANOHR):		6,624	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		924.19	
	c. Direct Construction Cost ($/kW):	($2014)	774.74	
	d. AFUDC Amount ($/kW):		99.90	
	e. Escalation ($/kW):		49.55	
	f. Fixed O&M ($/kW-yr):	($2014)	6.15	
	g. Variable O&M ($/MWh):	($2014)	2.03	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:		**Undesignated CC**	
(2)	Capacity			
	a. Summer:		793	
	b. Winter:		866	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2018	
	b. Commercial in-service date:		6/2021	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst	
(7)	Cooling Method:		Cooling Tower	
(8)	Total Site Area:		UNKNOWN	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		6.66	%
	b. Forced Outage Factor (FOF):		6.36	%
	c. Equivalent Availability Factor (EAF):		87.40	%
	d. Resulting Capacity Factor (%):		75.6	%
	e. Average Net Operating Heat Rate (ANOHR):		6,741	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		1,613.11	
	c. Direct Construction Cost ($/kW):	($2014)	1,281.90	
	d. AFUDC Amount ($/kW):		146.84	
	e. Escalation ($/kW):		184.37	
	f. Fixed O&M ($/kW-yr):	($2014)	6.60	
	g. Variable O&M ($/MWh):	($2014)	5.45	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

DEF does not anticipate having any Directly Associated Lines with the designated units in Schedule 8

INTEGRATED RESOURCE PLANNING OVERVIEW

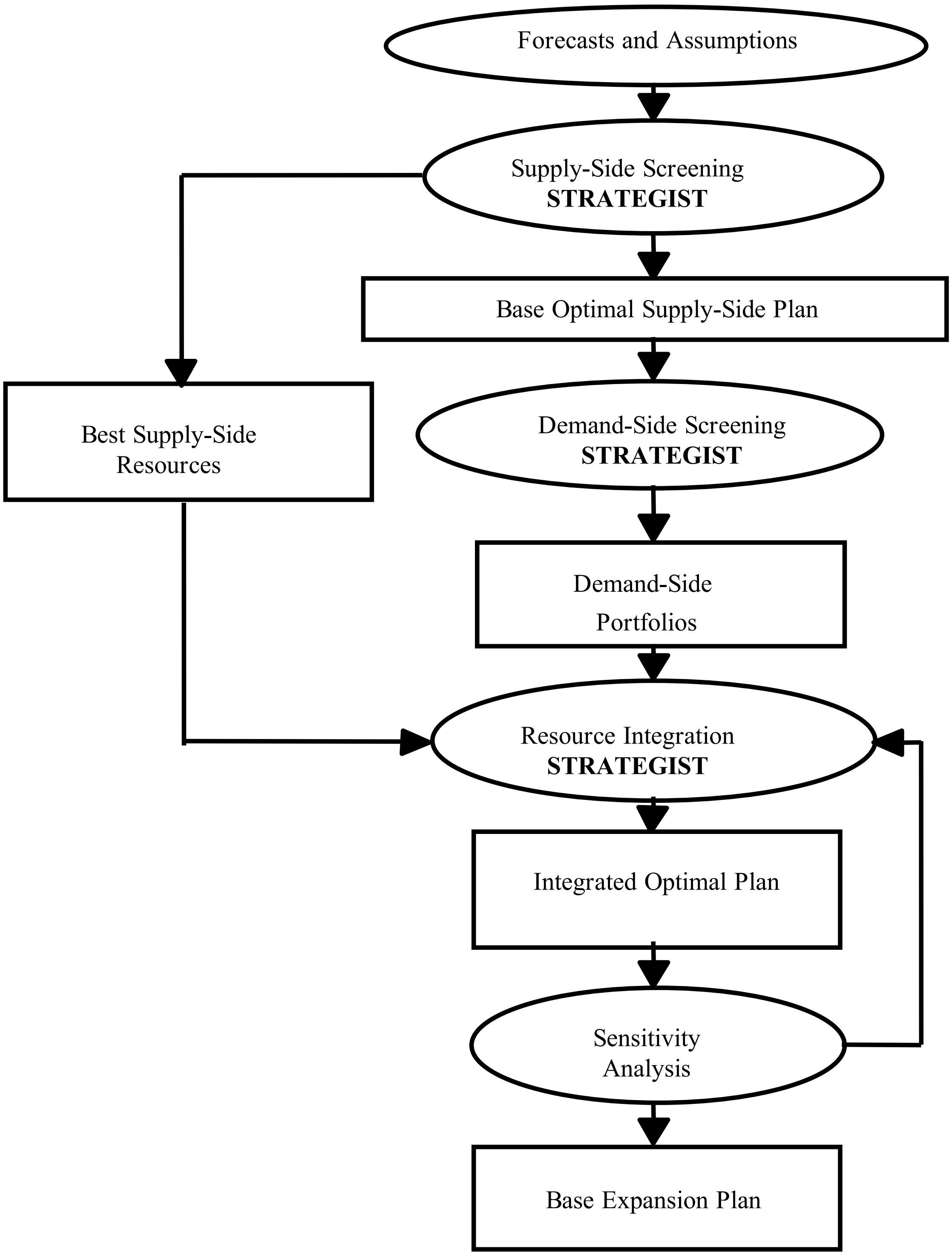
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of DEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for DEF to pursue over the next ten years to meet the Company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides DEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect DEF's view of the most likely future scenario are developed. Additional future scenarios along with high and low forecasts may also be developed. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for DEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

DEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF plans its resources to satisfy a 20 percent Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

DEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. DEF's resource portfolio is designed to satisfy the 20 percent Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20 percent Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and DEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters (e.g. possible climate legislation), and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the Strategist® optimization program. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements.

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources are also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (e.g. building code), or not applicable to DEF's customers. Strategist® is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. Strategist® calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test.

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the Company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and reasonable revenue requirements (rates) for DEF's ratepayers.

Developing the Base Expansion Plan

The integrated optimized plan that provides the lowest revenue requirements may then be further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it would then be considered the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP.

Fuel Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in DEF's most recent planning studies were 50 percent debt and 50 percent equity capital structure, projected cost of debt of 3.75 percent, and an equity return of 10.5 percent. The assumptions resulted on a weighted average cost of capital of 7.13 percent and an after-tax discount rate of 6.46 percent.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site.

DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan.

DEF continues to look ahead to the projected retirements of several of the older units in the fleet, particularly combustion turbines at Higgins, Avon Park, Turner and Rio Pinar as well as the three steam units at Suwannee. Turner Unit P3 is projected to retire at the end of 2014.The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. There are many factors which may impact these retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs.

Through its ongoing planning process, DEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

DEF continues to make purchases from the following facilities listed by fuel type:

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 MW)

Pasco County Resource Recovery (23 MW)

Pinellas County Resource Recovery (54.8 MW)

Waste Heat from Exothermic Processes:

PCS Phosphate (As Available)

Waste Wood, Tires, and Landfill Gas:

Ridge Generating Station (39.6 MW)

Photovoltaics

DEF owned installations (approximately 930 kW)

DEF's Net Metering Tariff includes over 12.5 MW of solar PV

In addition, DEF has contracts with U.S. EcoGen (60 MW) and Florida Power Development (60 MW). U.S. Ecogen will utilize an energy crop, while the Florida Power Development facility utilizes wood products as its fuel source.

DEF has also signed several As-Available contracts utilizing biomass and solar PV technologies.

A summary of renewable energy resources is below.

Supplier	Size (MW)	Currently Delivering?	Anticipated In-Service Date
Lake County Resource Recovery	12.8	Yes	
Pasco County Resource Recovery	23	Yes	
Pinellas County Resource Recovery	54.8	Yes	
Ridge Generating Station	39.6	Yes	
PCS Phosphate	As Avail	Yes	
Florida Power Development, LLC	60	Yes	
U.S. EcoGen Polk	60	No	1/1/17
DEF owned Photovoltaics	1	Yes	
Net Metered Customers (1,118)	12.5	Yes	
Blue Chip Energy - Sorrento	As Avail	No	See Note Below
National Solar - Gadsden	As Avail	No	See Note Below
National Solar - Hardee	As Avail	No	See Note Below
National Solar - Highlands	As Avail	No	See Note Below
National Solar - Osceola	As Avail	No	See Note Below
National Solar - Suwannee	As Avail	No	See Note Below

Note: As Available purchases are made on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required.

DEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. DEF continues to keep an open Request for Renewables (RFR) soliciting proposals for renewable energy projects. DEF's open RFR continues to receive interest and to date has logged over 315 responses. DEF will continue to submit renewable contracts in compliance with FPSC rules.

Depending upon the mix of generators operating at any given time, the purchase of renewable energy may reduce DEF's use of fossil fuels. Non-intermittent renewable energy sources also defer or eliminate the need to construct more conventional generators.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize.

TRANSMISSION PLANNING

DEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing, and to assure the system meets DEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. DEF normally runs this analysis for system peak and off-peak load levels for possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, transmission lines, or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the DEF reliability criteria, some remedial actions are allowed to reduce system loadings; in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

DEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID_Posted_Rev2.docx.
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_3.docx

DEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev2.docx

DEF proposed bulk transmission line additions are summarized in the following Table 3.3. DEF has listed only the larger transmission projects. These projects may change depending upon the outcome of DEF's final corridor and specific route selection process.

TABLE 3.3
DUKE ENERGY FLORIDA
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2014 – 2023

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1000	DEF	DEBARY	ORANGE CITY	6	11/30/2015	230

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

DUKE ENERGY.
FLORIDA

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

DEF's 2014 TYSP Preferred Sites include Citrus County for Combined Cycle natural gas generation (and adjacent to the DEF Crystal River Site) and Suwannee County for Simple Cycle natural gas generation. DEF's expansion plan beyond this TYSP planning horizon includes potential nuclear power at the Levy County greenfield. The Citrus County, Suwannee County and Levy County Preferred Sites are discussed below.

SUWANNEE COUNTY

DEF has identified the existing Suwannee River Energy Center site in Suwannee County for simple cycle CTs (see Figure 4.1.a below). The proposed power block includes two (2) dual fuel CTs using F-class technology. The project area totals approximately 68 acres and is located west of River Road, south of U.S. 90. The project area consists of a naturally occurring pine-oak community of the subject parcel and has a canopy primarily composed of longleaf and slash pine as well as turkey and laurel oak. There are no wetlands within the limits of the project area.

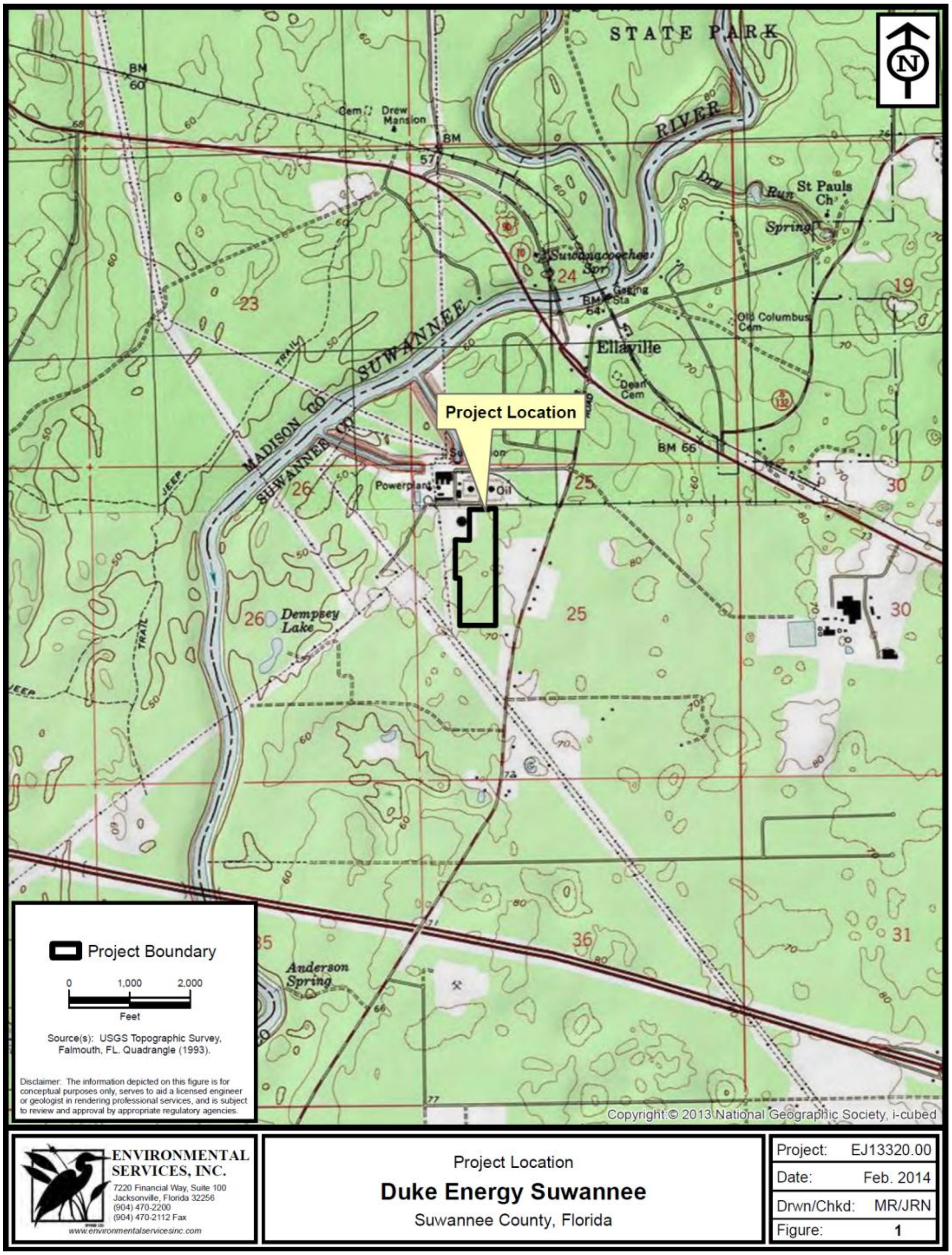
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. DEF will acquire a permit from the Florida Fish and Wildlife Conservation Commission to relocate any gopher tortoises from the project area prior to construction. No archaeological or cultural resources will be adversely impacted by the project.

The new project will not require an increase of water use beyond what is already permitted to be used by the site from the Suwannee River Water Management District. Development of the project site will also require an Environmental Resource Permit and Air Permit from the Florida

Department of Environmental Protection. Suwannee County requires a special exception approval to construct the project on the property.

FIGURE 4.1.a

Suwanee County Preferred Site Location



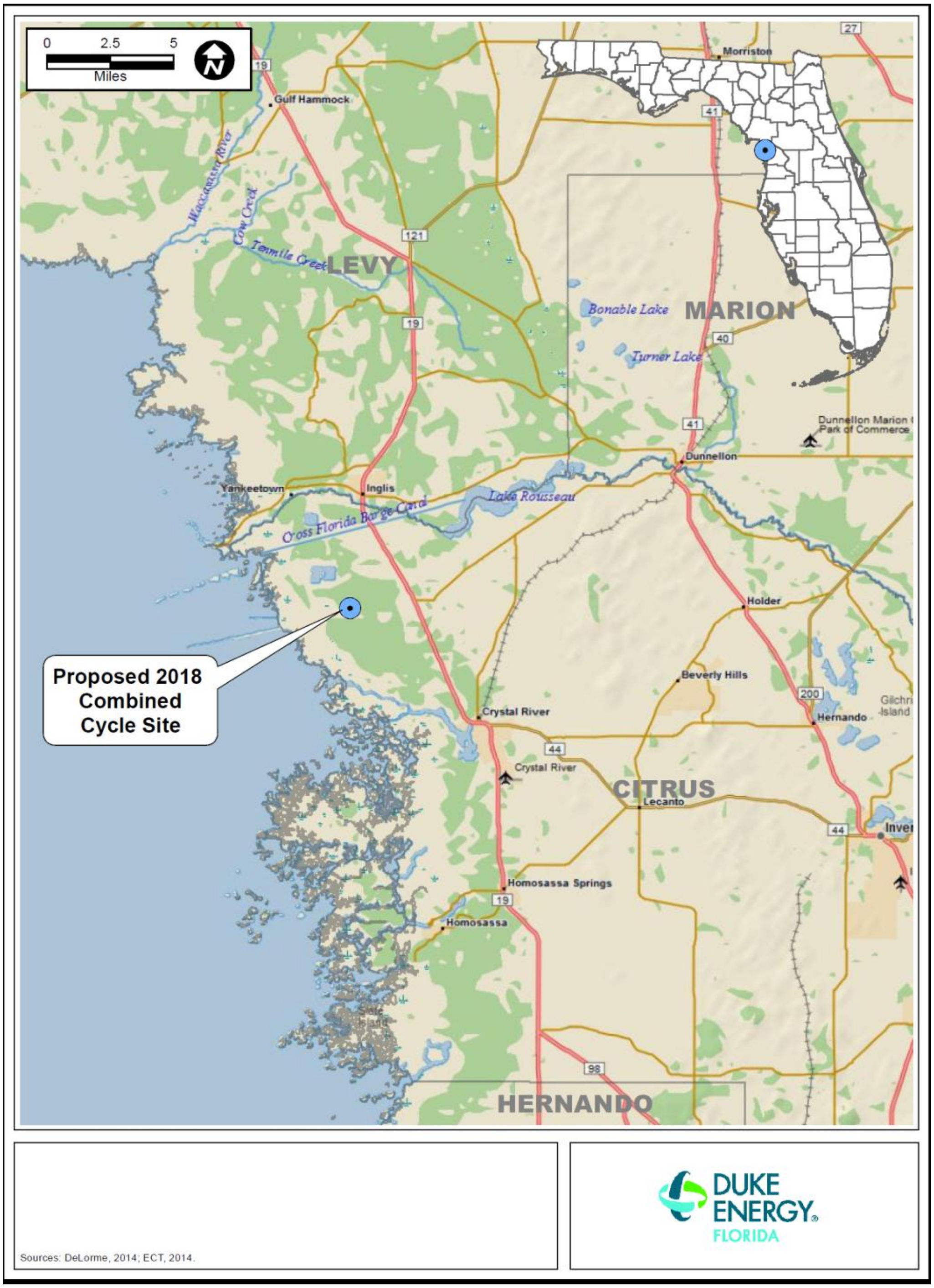
CITRUS COUNTY

DEF has identified a site in Citrus County as a preferred site for new combined cycle generation (see Figure 4.1.b below). The Company is planning for the construction of a new combined cycle facility on the property with the unit coming on line during 2018. The Citrus site consists of approximately 400 acres of property located immediately north of the Crystal River Energy Center (CREC) transmission line right-of-way and east of the Crystal River Units 4 and 5 coal ash storage area and north of the DEF Crystal River to Central Florida 500-/230-kV transmission line right-of-way. The property consists of regenerating timber lands, forested wetlands, and rangeland bounded to the south by the CREC North Access Road. The site is currently part of the Holcim mine. A new natural gas pipeline will be brought to the Project Site by the natural gas supplier on right of way provided by the supplier. The water pipelines and transmission lines will use existing DEF rights-of-way. No new rail spur is proposed and site access will be via existing roadways.

DEF's assessment of the Citrus site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. No significant issues were identified in DEF's evaluations of the property. The site will be certified by the State of Florida under the Power Plant Siting Act. Federal permits for the development of the site will include a National Pollution Discharge Elimination System (NPDES) permit, Title V Air Operating Permit and a Clean Water Act Section 404 Permit. The site will require Land Use Approval from Citrus County. The new project is proposing to use the existing CR3 intake structure and a new discharge structure in the existing discharge canal.

FIGURE 4.1.b

Citrus County Preferred Site Location



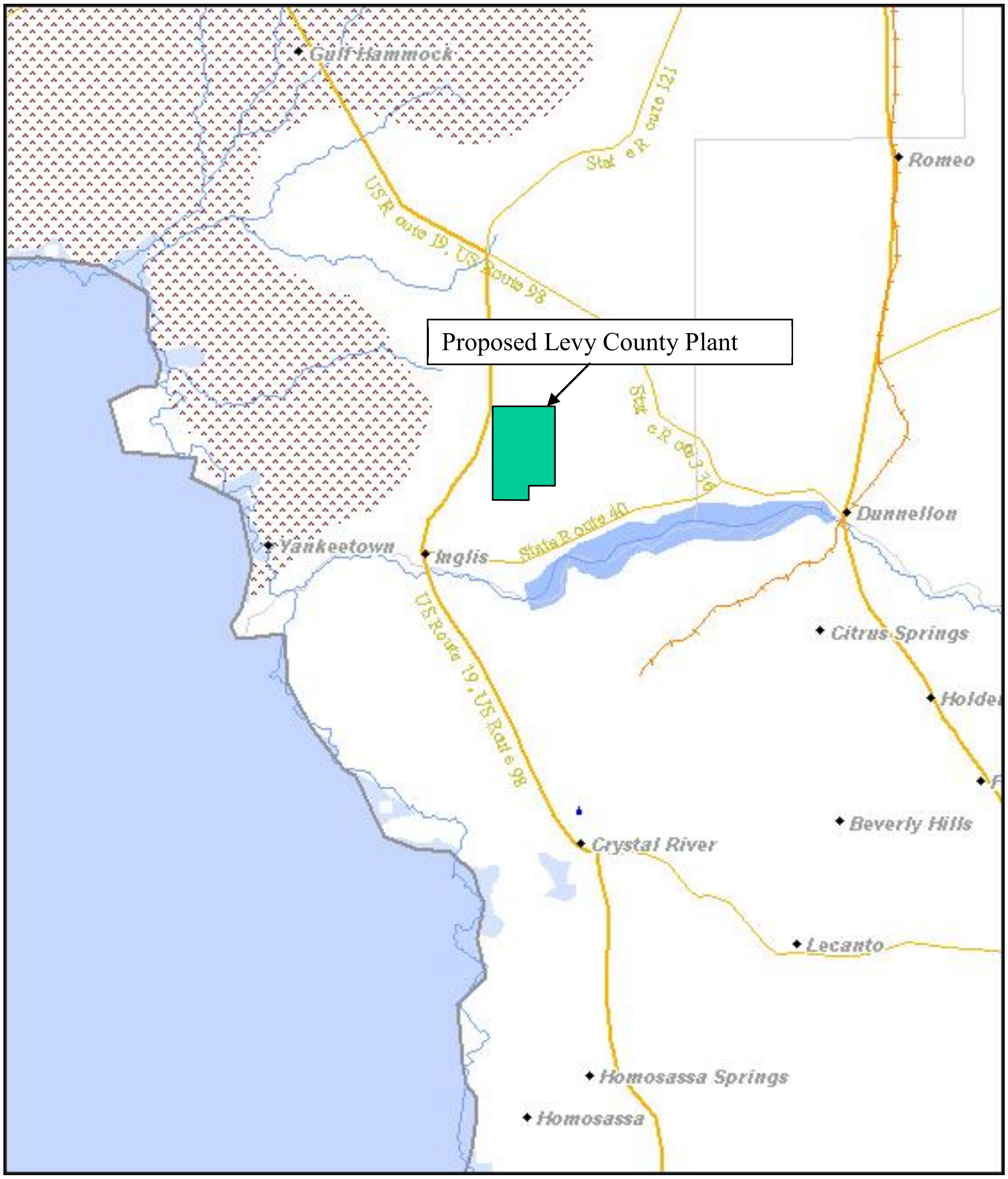
LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

Although the proposed Levy Nuclear Project is no longer an option for meeting energy needs within the originally scheduled time frame, Duke Energy Florida continues to regard the Levy site as a viable option for future nuclear generation and understands the importance of fuel diversity in creating a sustainable energy future. Because of this the Company will continue to pursue the combined operating license outside of the Nuclear Cost Recovery Clause with shareholder dollars as set forth in the 2013 Settlement Agreement. The Company will make a final decision on new nuclear generation in Florida in the future based on, among other factors, energy needs, project costs, carbon regulation, natural gas prices, existing or future legislative provisions for cost recovery, and the requirements of the NRC's combined operating license.

The Levy County site is shown in Figures 4.1.c below:

FIGURE 4.1.c

Levy County Nuclear Power Plant (Levy County)



DEF's Near Term Summer and Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,170	8,812	39,801
2015	9,133	9,042	40,490
2016	9,370	9,149	41,098
2017	9,298	9,307	41,375

DEF's Forecast of Summer Peak Demands and Reserves With and Without Additional Generation Capacity in the Summers of 2016 and 2017

		Including Suwannee CTs and Hines Inlet Chillers		Excluding Suwannee CTs and Hines Inlet Chillers	
Year	Summer Firm Peak Demand	Summer Installed Capacity	Summer Reserve Margin (%)	Summer Installed Capacity	Summer Reserve Margin (%)
2014	8,812	11,024	25.1%	11,024	25.1%
2015	9,042	10,991	21.6%	10,991	21.6%
2016	9,149	11,012	20.4%	10,696	16.9%
2017	9,307	11,232	20.7%	10,696	14.9%

DEF's Forecast Of Physical And Dispatchable Demand-Side Resource Reserves Through the Summers of 2016 And 2017

Year	Summer				
	Peak Demand Before DR	Dispatchable Demand Side Resources	Net Firm Demand	Total Installed Capacity	Reserve Margin
2014	9,641	829	8,812	11,024	25.1%
2015	9,882	840	9,042	10,991	21.5%
2016	9,997	848	9,149	11,012	20.4%
2017	10,196	889	9,307	11,232	20.7%

GENERATION OPTIONS EVALUATED TO CONTRIBUTE TO DEF'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

New Simple Cycle Units: Suwannee River Plant preferred location (*Selected*)

Thermal Power Uprates: Update compressor, turbine and controls components in the combustion turbines to current design and firing temperatures.

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's
- Hines PB2 Combined Cycle – 2 CT's
- Hines PB3 Combined Cycle – 2 CT's
- Hines PB4 Combined Cycle – 2 CT's

Inlet Chilling: Install electric driven chillers and thermal storage systems to cool inlet air to the combustion turbines during the warm summer months

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's (*Selected*)
- Hines PB2 Combined Cycle – 2 CT's (*Selected*)
- Hines PB3 Combined Cycle – 2 CT's (*Selected*)
- Hines PB4 Combined Cycle – 2 CT's (*Selected*)

Other operations-focused options evaluated and implemented at the Bartow 4 Combined Cycle Plant:

- Replace the steam turbine LP L-0 row turbine blades at the with the OEM's current design

REDACTED

[redacted]

INITIAL DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build									
$M 2013	PPA 1	PPA 2	PPA 3	Acquisition 2	Acquistion 1	Acquisition - PPA Mix 1	Acquisition - PPA Mix 2	Acquistion 3	Acquistion 4
Capital Costs	37	90	90	(49)	204	101	101	23	(35)
Fuel	395	141	45	(50)	16	(12)	260	7	(3)
Emissions	19	23	19	(71)	(47)	(3)	15	13	1
Variable Costs	19	(4)	(9)	113	34	(4)	10	(0)	1
Fixed Costs	(36)	(122)	(122)	(148)	(162)	(129)	(129)	(310)	(351)
PPAs	(567)	(270)	(184)	44	10	(65)	(375)	9	2
Cogens	(1)	5	6	(36)	(9)	0	(2)	0	1
Emergency Energy	4	2	0	4	2	2	2	3	(2)
Total	(129)	(136)	(155)	(193)	49	(110)	(118)	(255)	(386)

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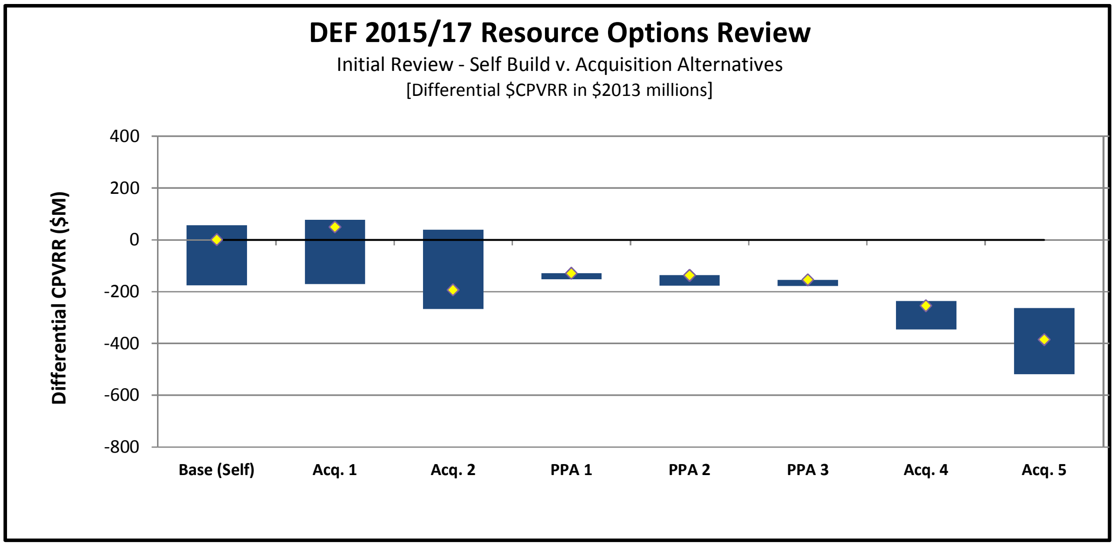
COMPANY'S COST SENSITIVITY ANALYSIS RESULTS BASED ON THE INITIAL DETAILED ECONOMIC ANALYSIS



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DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017.

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build				
$M 2014	Acquisition - PPA Mix 1	PPA 1	Self Build No Hines Chillers	Self Build plus Hines 1 Chillers
Capital Costs	88	83	52	(33)
Fuel	50	227	(36)	68
Emissions	16	29	(24)	19
Variable Costs	(9)	2	13	(2)
Fixed Costs	(141)	(129)	(7)	5
PPAs	(143)	(332)	(27)	(29)
Cogens	1	3	(0)	(2)
Emergency Energy	(1)	(1)	3	1
Total	(139)	(118)	(26)	26

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COMPANY'S ANALYSIS OF GAS PRICE AND CO2 COST SENSITIVITIES TO THE FINAL DETAILED ECONOMIC ANALYSES

High Gas Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	35	267	53
Emissions	15	29	21
Variable Costs	(10)	2	(4)
Fixed Costs	(141)	(129)	5
PPAs	(123)	(364)	(1)
Cogens	1	3	(1)
Emergency Energy	(1)	(1)	1
Total	(138)	(110)	41

No CO2 Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	23	205	46
Emissions	(13)	(12)	(1)
Variable Costs	(9)	3	(2)
Fixed Costs	(141)	(129)	5
PPAs	(117)	(311)	(2)
Cogens	(0)	1	(1)
Emergency Energy	(1)	(1)	1
Total	(170)	(161)	14