BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	)))	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-2 through BMHB-14 in support of DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

Respectfully submitted this 27th day of May, 2014.

/s/ James Michael Walls

John T. Burnett
Deputy General Counsel
Dianne M. Triplett
Associate General Counsel
DUKE ENERGY FLORIDA, INC.
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (727) 820-5587
Facsimile: (727) 820-5519

James Michael Walls
Florida Bar No. 0706242
Blaise N. Gamba
Florida Bar No. 0027942
CARLTON FIELDS JORDEN BURT, P.A.
Post Office Box 3239
Tampa, FL 33601-3239
Telephone: (813) 223-7000
Facsimile: (813) 229-4133

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	DOCKET NO. ____________ Submitted for filing: May 27, 2014

DIRECT TESTIMONY
OF BENJAMIN M.H. BORSCH

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

JOHN T. BURNETT
Deputy General Counsel
DIANNE M. TRIPLETT
Associate General Counsel
DUKE ENERGY FLORIDA, INC.
299 1st Avenue North
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

JAMES MICHAEL WALLS
Florida Bar No. 706272
BLAISE N. GAMBA
Florida Bar No. 027942
CARLTON FIELDS JORDEN
BURT, P.A.
4221 W. Boy Scout Blvd., Ste.1000
Tampa, Florida 33607
Telephone: (813) 223-7000
Facsimile: (813) 229-4133

IN RE: PETITION FOR DETERMINATION OF NEED

BY DUKE ENERGY FLORIDA

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 request for proposals ("2018 RFP") to meet the Company's reliability needs commencing in the summer of 2018 consistent with Commission rule 25-22.082, F.A.C. (the "Bid Rule") and the Company's evaluation of the proposals received in response to that 2018 RFP.

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, Inc. and, following the 2012 merger with Duke Energy, I accepted my current position with the Company. Prior to joining Progress Energy, I was employed for more than five 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 eight 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 Duke Energy Florida in support of its Petition for Determination of Need for the Citrus County Combined Cycle Power Plant. I will introduce all of the Company's witnesses in the proceeding. I will also provide an overview of the Citrus County Combined Cycle Power Plant that the Company proposes to build. I will discuss DEF's Integrated Resource Planning ("IRP") process and how that process led the Company to identify the Citrus County Combined Cycle Power Plant as its next-planned generation. I will also explain the Company's need for the Citrus County Combined Cycle Power Plant, and describe the steps the Company has taken to seek out available, superior supply-side alternatives through the 2018 RFP process. I will describe the Company's 2018 RFP for supply-side alternatives to its next planned generating unit ("NPGU"), I will provide the Company's evaluation of the competing proposals received in response to that 2018 RFP, and I will explain why the Company's NPGU, its Citrus County Combined Cycle Power Plant, is the most cost-effective alternative to meet the Company's reliability needs commencing in 2018. I will conclude my testimony by explaining the Company's decision to proceed with the Citrus County Combined Cycle Power Plant, consistent with the factors in Section 403.519(3), Florida Statutes. More detailed information concerning the Company's decision to build the Citrus County Combined Cycle Power Plant is contained in the Company's Need Determination Study for the Citrus County Combined Cycle Power Plant included as Exhibit No. ___ (BMHB-1) to my testimony.

Q. Are you sponsoring Duke Energy Florida's Need Study?

A. Yes. In general, I am the sponsor of the Need Study. The Need Study was prepared under my direction, and it is true and accurate.

Q. Is the process you outlined in the purpose of your testimony in this proceeding consistent with the 2013 Settlement Agreement?

A. Yes. The Company explained in the Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") that the Company projected a need for additional generation capacity in 2018, and that the Company may petition the Commission for a need determination for additional generation, not to exceed 1,800 MegaWatts ("MW"), to be placed in service in 2018 to meet that need. The Company's decision to select the 1,640 MW Citrus County Combined Cycle Power Plant as its NPGU; to solicit competing proposals to the NPGU to determine the most cost effective generation alternative to meet the Company's generation capacity need in 2018; and to file the current Company Petition with the Commission, is consistent with the process the Company identified in the 2013 Settlement Agreement. DEF has met with the parties to the 2013 Settlement Agreement several times to explain this process for meeting DEF's generation needs in 2018 and, ultimately, DEF's decision to meet that need consistent with that process. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

Q. Are you sponsoring any exhibits to your testimony?

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

- Exhibit No. ___ (BMHB-1), the Company's Need Study for the Citrus County Combined Cycle Power Plant;
- Exhibit No. ____ (BMHB-2), the Company's April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), DEF's projected summer peak load growth and Reserve Margins with and without additional generation resources through 2018;
- Exhibit No. ___ (BMHB-4), DEF's projected net energy for load growth on DEF's system;
- Exhibit No. ___ (BMHB-5), a comparison of the cost efficiency of commercially available generation technologies including combined cycle generation technology;
- Exhibit No. ___ (BMHB-6), a map of the location of unconventional shale gas developments and major gas pipelines in the Southeast United States;
- Exhibit No. ___ (BMHB-7), a chart of the recent, current, and future production from both conventional and unconventional North American gas supply resources;
- Exhibit No. ___ (BMHB-8), a map showing the location of the Sabal Trail Transmission LLC ("Sabal Trail") natural gas pipeline and the other natural gas pipelines into the State of Florida;
- Exhibit No. ___ (BMHB-9), a flow chart of the 2018 RFP evaluation process;

- Exhibit No. ___ (BMHB-10), a table of the 2018 RFP Threshold Requirements;
- Exhibit No. ___ (BMHB-11), a table of the 2018 Minimum Technical Requirements;
- Exhibit No. ___ (BMHB-12), a table of the 2018 RFP bidder proposal resource scenarios evaluated in the Company's 2018 RFP evaluation process;
- Exhibit No. ___ (BMHB-13), a table of the results of the Company's Initial Detailed Evaluation of the 2018 RFP bidder proposal resource scenarios; and
- Exhibit No. ___ (BMHB-14), a table of the results of the Company's Detailed Evaluations of the 2018 RFP bidder proposal resource scenarios and the Company's sensitivity analyses in its 2018 RFP evaluation.

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

Q. Please give an overview of the Company's presentation in this proceeding.

A. In addition to my own testimony, the Company will present the testimony of the following witnesses in support of its petition for determination of need for the Citrus County Combined Cycle Power Plant:

- Mr. Mark Landseidel will testify about the site and unit characteristics for the Citrus County Combined Cycle Power Plant, including the size, equipment configuration, fuel type and supply modes; the estimated costs of the Plant; and the Plant's projected in-service date;

- Ms. Amy Dierolf will describe the Citrus County site, discuss the environmental benefits of the site and the Citrus County Combined Cycle Power Plant, and describe the environmental approval process associated with the construction and operation of the Plant;
- Mr. Jeffrey Patton will discuss the Company's fuel supply plan for the Citrus County Combined Cycle Power Plant;
- Mr. Kevin Delehanty provides the Company's fuel forecast and describes the development of that forecast;
- Mr. Ed Scott will discuss the transmission requirements for the Citrus County Combined Cycle Power Plant and the transmission requirements for the proposals submitted in response to DEF's 2018 RFP; and
- Mr. Alan Taylor with Sedway Consulting, Inc. will provide testimony as the independent monitor retained by DEF to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP documents were clear, fair, and consistent with Commission rules. Mr. Taylor was also retained as an independent evaluator of the 2018 RFP bid proposals and will provide testimony that DEF's evaluation of the proposals received in response to the 2018 RFP was fair and impartial and that the Company's selection of the Citrus County Combined Cycle Power Plant NPGU as the most cost-effective option to meet DEF's reliability need was reasonable.

Q. Please summarize your testimony.

A. DEF needs additional generation capacity in 2018 to reliably serve its customers. Improving customer and peak demand growth in Florida following the recession contribute to this need, but the need is primarily driven by current and planned DEF generation plant retirements that exceed the Company's MW reliability need in 2018. Largely as a result of these plant retirements, there are no cost-effective demand-side resources available to the Company that can offset or defer the Company's need for additional generation capacity to meet this reliability need. DEF's plant retirements in Citrus County lead to Florida electric grid reliability issues too, if additional generation is not added in Citrus County.

The Company identified the Citrus County Combined Cycle Power Plant as its NPGU to meet this reliability need after conducting a careful screening of various supply side alternatives in its resource planning process. The Citrus County Combined Cycle Power Plant is a highly efficient, state-of-the-art natural-gas fired combined cycle generation plant located on a favorable site in Citrus County that takes advantage of adjacent DEF site infrastructure and transmission facilities that contribute to the cost effectiveness of the NPGU for DEF's customers.

DEF solicited competing alternatives to its NPGU through its 2018 RFP and no bidder in response to the 2018 RFP proposed a plant that came close to matching the benefits of the Citrus County Combined Cycle Power Plant for DEF's customers. The Citrus County Combined Cycle Power Plant is clearly the most cost effective generation resource for DEF's customers.

The Citrus County Combined Cycle Power Plant allows DEF to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost in the most cost-effective manner. The Plant further modernizes and adds diversity to DEF's generation fleet in terms of natural gas fuel supply diversity, technology, age, and functionality of the Plant. For all these reasons, DEF requests Commission approval of its Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

III. OVERVIEW: CITRUS COUNTY COMBINED CYCLE POWER PLANT.

Q. Please describe the Citrus County Power Plant.

A. The Citrus County Combined Cycle Power Plant will be a state-of-the-art, natural gas-fired, combined cycle power plant with an expected summer rating of 1,640 MW and an expected winter rating of 1,820 MW when completed in December 2018. Construction of 820 MW of the 1,640 MW plant will be completed by June 2018, with the remaining 820 MW completed by December 2018. The plant will be highly efficient with high availability for operation on DEF's system. More details about the Citrus County Combined Cycle Power Plant, and its construction and operating characteristics, are provided by Mr. Landseidel in his direct testimony in this proceeding.

Q. Where will the Company build the Citrus County Combined Cycle Power Plant?

A. DEF will build the Plant at a new site in Citrus County, Florida next to the Company's existing Crystal River Energy Complex ("CREC"). The site is a 400 acre parcel bounded on the west by the CREC site. The southern boundary of the site is the current Power Line Road running east to west into the CREC.

The Company will seek Site Certification from the Florida Department of Environmental Protection ("FDEP") and the Florida Siting Board for the Citrus

County site in order to build the Citrus County Combined Cycle Plant. The Company's Site Certification application for the Plant site will be filed with the FDEP in August 2014. This process is described in more detail in the direct testimony of Amy Dierolf in this proceeding.

Q. Are there advantages to building the Citrus County Combined Cycle Power Plant adjacent to the CREC?

A. Yes. The location of the plant adjacent to the CREC allows the Company to use existing CREC infrastructure for the development, construction, and operation of the Plant. This infrastructure provides construction and operational synergies that result in construction and operation cost efficiencies for the Plant compared to typical green field sites.

The most significant infrastructure synergies arise from the existing transmission infrastructure near the site that is now available for transmitting the power from the Citrus County Combined Cycle Power Plant to DEF's system because of the Company's current and planned CREC generation facility retirement decisions. The retirement of the Company's nuclear power plant at the CREC, and the planned retirement of the Company's oldest, coal-fired power plants at the CREC by the time the Citrus County Combined Cycle Power Plant achieves commercial operation, frees up transmission capacity on the existing transmission infrastructure for the Citrus County Combined Cycle Power Plant capacity. As a result, no transmission system upgrades or additions are necessary to add the Citrus County Combined Cycle Power Plant to the Company's system. The only expected transmission costs are the costs necessary to connect the Citrus County Combined Cycle Power Plant to Florida's interconnected electrical grid. The ability to add the Citrus Country Combined Cycle Power Plant to DEF's system without transmission system additions or modifications is one of the synergistic benefits from constructing the Citrus County Combined Cycle Power Plant at the Citrus County site.

Other synergistic benefits include the ability to use the existing CREC intake canal as the water source for the sea water cooling towers for the Citrus County Combined Cycle Power Plant. DEF will also be able to use the existing CREC fresh water wells for process make up water. These CREC resources allow DEF to avoid development and construction costs to provide the make-up water required to cool the Plant and to operate the facility, thus, lowering the cost to construct and operate the Citrus County Combined Cycle Power Plant at the Citrus County site compared to other green field sites.

DEF will also be able to use the existing roads, buildings and other structures at the CREC during the construction and operation of the Citrus County Combined Cycle Power Plant. These synergistic benefits from locating the Citrus County Combined Cycle Power Plant adjacent to the CREC are explained further by Mr. Landseidel in his direct testimony. All of these existing infrastructure resources provide cost-savings synergies for the construction and operation of the Citrus County Combined Cycle Power Plant at the Citrus County site compared to other green field sites.

Q. What will it cost to build the Citrus County Combined Cycle Power Plant?

A. The cost to build the Citrus County Combined Cycle Power Plant is estimated to be $1,350 million (nominal dollars), plus $164 million (nominal dollars) for Allowance for Funds Used During Construction ("AFUDC"), for a total cost of $1,514 million. This includes the cost of equipment; the Engineering, Procurement, and Construction ("EPC") contract; licensing; and internal costs such as construction management and start-up costs.

Q. Is the Citrus County Combined Cycle Power Plant the most cost-effective resource for DEF and its customers?

A. Yes. We believe that the Citrus County Combined Cycle Power Plant will enable the Company to meet the reliability needs of our customers, it will provide a superior source of efficient, cost-effective power to our customers during its life, and that it adds flexibility to the energy production resources on the DEF system. There simply is no more cost-effective, viable generation resource to meet DEF's capacity needs beginning in 2018 to provide reliable power to DEF's customers.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain DEF's Resource Planning Process.

A. The Resource Planning process is an integrated process in which the Company seeks to optimize its supply-side options along with its demand-side options into a final, integrated optimal plan, designed to deliver reliable, cost-effective power to DEF's customers. We evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed during the planning period. The generation plan is optimized after including cost-effective DSM programs to establish the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This optimal plan is presented to the Commission in April each year in the Company's annual TYSP filing. The April 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony. The Company's IRP process is also described in more detail in the Need Study attached as Exhibit No. ___ (BMHB-1) to my testimony.

Q. What are the reliability standards the Company used to determine the need for additional resources?

A. 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. 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 in its IRP process since the early 1990s. DEF's resource plans, based on these dual-reliability criteria, have been reviewed by the Commission each year since the early 1990s in the annual TYSP review process. 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 all expected load conditions.

Q. Why are reserves needed?

A. Utilities require 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 load 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 minimum planning Reserve Margin?

A. DEF's minimum Reserve Margin threshold is 20 percent. The Commission established this Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Order No. PSC-99-2507-S-EU. The Reserve Margin is a deterministic measure of reliability.

Q. What is LOLP and what does it measure?

A. LOLP is a probabilistic reliability criterion that measures the probability that a utility will be unable to meet its load throughout the year. The Reserve Margin considers only the peak load and amount of installed resources, while the LOLP considers these factors and 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 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.

Q. Do both criteria drive the decision to add additional resources?

A. Generally, the need for additional resources will be required by the Reserve Margin criterion before the LOLP criterion is reached. That is the case for the Company's need for additional generation resources in 2018. This reliability need is driven by DEF's commitment to meet the 20 percent Reserve Margin for its customers.

Q. Can you describe DEF's Resource Planning process?

A. Yes. The IRP process begins with the forecast of system load growth that is developed for the next ten years. This forecast draws on the collection of certain input data, such as population growth, fuel prices, interest and inflation rates, and the development of economic and demographic assumptions that impact future energy sales and customer demand. The Company regularly updates its load forecast during the course of the year and for the development of the resource plan presented in the Company's annual TYSP. The development of the Company's load forecast for its 2018 RFP and current 2014 TYSP is explained in more detail in the Company's Need Study in Exhibit No. ___ (BMHB-1) and in the Company's 2014 TYSP included as Exhibit No. ___ (BMHB-2) to my testimony.

Q. What were the results of the Company's load forecasts?

A. By the summer of 2018, when the Citrus County Combined Cycle Power Plant is projected to first come on-line, the summer peak demand is projected to grow to 9,439 MW and by the next summer, when the Citrus County Combined Cycle Power Plant is expected to be fully operational, the summer peak demand is projected to reach 9,813 MW. The annual growth in peak summer demand is approximately 1.4 percent over the current ten year forecast period. This peak summer demand growth results in a summer Reserve Margin of 11.7 percent by 2018 without additional resources to DEF's system. This result is depicted in Exhibit No. ___ (BMHB-3) to my direct testimony.

DEF maintains its Reserve Margin for both its summer and winter peak demands to ensure that DEF provides reliable electric service to its customers. DEF needs additional generation in the summer of 2018 to meet its 20 percent minimum Reserve Margin commitment. Exhibit No. ___ (BMHB-3) shows DEF's forecast of summer peak demand and reserves, with and without the Citrus County Combined Cycle Power Plant generation capacity addition. As demonstrated in this exhibit, without the Citrus County Combined Cycle Power Plant generation capacity addition, DEF's summer Reserve Margin will decrease to 11.7 percent in the summer of 2018 and 6.9 percent by the summer of 2019.

The net energy for load is also projected to grow over the same time period. The net energy for load is projected to be 41,995 gigawatt-hours ("GWh") in 2018 and 43,013 GWh in 2019, respectively, which is a 1.4 percent growth rate. The growth in demand and energy is primarily a result of increasing customer growth and improving economic conditions in Florida following the past recession. Exhibit No. ___ (BMHB-4) is a table including the projected net energy for load growth on DEF's system.

More information regarding the demand and energy forecasts, and the methodology used to develop them, is included in the Need Determination Study in Exhibit No. ___ (BMHB-1) and in Chapter 2 of the Company's TYSP, which is Exhibit No. ____ (BMHB-2) to my direct testimony.

Q. Is load growth the only factor driving the Company's reliability needs commencing in the summer of 2018?

A. No. Generation facility retirements also contribute to the Company's reliability needs in the summer of 2018. In February 2013, the Company decided to retire Crystal River Unit 3 ("CR3"), its nuclear power plant at the CREC. CR3 provided DEF's system with approximately 790 MW in summer capacity, after allowing for joint owner shares in the plant capacity, which was no longer available to meet DEF's future capacity needs when DEF decided to retire the plant. This retirement decision was first reflected in the Company's 2013 TYSP and its impact is included in DEF's IRP process in the 2014 TYSP.

In addition to the CR3 retirement, the Company also plans to retire its oldest coal-fired generation plants, Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2"), also located at the CREC. CR1 and CR2 are 1960's vintage coal-fired generation with a combined summer capacity of about 740 MW. Current air permits allow the Company to continue operation of CR1 and CR2 through 2020, if CR1 and

CR2 meet all applicable environmental regulations. The United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"), however, established new air emission standards and limits that affect the continued operation of CR1 and CR2 through 2020 without substantial investment in new environmental compliance equipment and measures for CR1 and CR2. As a result, the Company evaluated the retirement of CR1 and CR2 prior to 2020.

Q. What EPA and FDEP regulations impact the Company's ability to continue to operate CR1 and CR2 through 2020?

A. Most recently, the EPA issued its final rule replacing the Clean Air Mercury Rule ("CAMR"), which was vacated by the United States Court of Appeals for the District of Columbia. CAMR was part of a series of EPA regulations addressing the emissions from fossil-fuel generation plants that include the Clean Air Interstate Rule ("CAIR") and the Clean Air Visibility Rule ("CAVR"). These regulations led DEF to develop an Integrated Clean Air Compliance Plan that was approved by the Commission in Order No. PSC-07-0922-FOF-EI. That Plan included the installation of emission control facilities and equipment at the Company's other coal-fired generation plants, Crystal River Units 4 ("CR4") and 5 ("CR5"), at the CREC, and the planned retirement of CR1 and CR2 in 2020.

As a result of CAVR, continued operation of CR1 and CR2 is subject to Best Available Retrofit Technology ("BART") and Reasonable Further Progress ("Beyond BART") requirements. These requirements fully go into effect in 2018, and to comply with them, the Company would have to install expensive Flue Gas

Desulfurization ("FGD") and Selective Catalytic Reduction ("SCR") equipment on CR1 and CR2 by 2018 or cease operation in 2020.

Early in 2012, the EPA replaced the vacated CAMR with the Mercury and Air Toxics Standards ("MATS") rule. The MATS rule imposes emission limits for mercury and other metals and acid gases from coal-fired and oil-fired electric utility generating units. Compliance with MATS is required within three years, or by April 2015, unless extended under certain, limited circumstances one year by the FDEP. DEF developed a plan for limited continued operation of CR1 and CR2 in compliance with MATS. This operation requires some modest upgrades to the units. The one-year MATS compliance extension was granted for CR1 and CR2 by FDEP based on the need for time to complete these upgrades. FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant grid reliability issues identified in the Florida Reliability Coordinating Council ("FRCC") MATS study completed in 2013.

Q. What did the Company decide to do with CR1 and CR2 based on its evaluation of these environmental regulations?

A. The Company determined that there was a cost-effective way to comply with the MATS and CAVR requirements and continue to operate CR1 and CR2 in the near term until replacement generation could be built or acquired and associated transmission projects, if needed, could be constructed. Based on the Company's evaluations and coal fuel tests, the Company decided that it could continue to operate CR1 and CR2 until mid-2018 by burning alternate coals and installing less expensive pollution controls than the FCD and SCR equipment at CR1 and CR2. The continued operation of CR1 and CR2 through mid-2018 resolved the near term grid reliability issues that the FRCC MATS study identified. As the MATS Study further recognized, the addition of a new combined cycle generation plant in the Citrus County vicinity in 2018, as first provided for in the Company's 2013 TYSP, fully resolved the grid reliability issues after 2018. Accordingly, DEF petitioned the Commission to modify its Integrated Clean Air Compliance Plan to incorporate these new environmental compliance activities for CR1 and CR2 and the Commission approved this modification in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014). The Company plans to retire CR1 and CR2 in 2018, when the Citrus County Combined Cycle Power Plant achieves commercial operation.

Q. Are these the only generation facility retirements that impact the Company's reliability needs by 2018?

A. No. The Company 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 smaller units provide a net 129 MW summer capacity to DEF's system. In addition, the Company plans to retire several of its oldest combustion turbine peaking units on its system between 2014 and 2016. All of these peaking units were built in the 1960's and early 1970's; they are some of the least efficient units on DEF's system; and they are increasingly more costly to maintain. They account for a total of 133 MW of summer capacity on DEF's system. All of these additional retirements are identified in the Company's current 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

It is the net impact of the Company's load growth and generation facility retirements that drive the need for additional generation on DEF's system by 2018 to meet the Company's reliability needs. DEF will satisfy part of these reliability needs by 2016 with the addition of its Suwannee Simple Cycle and Hines Chillers Power Uprate projects. These projects are described in DEF's separate petition to the Commission to determine the cost-effective generation alternative to meet DEF's reliability need prior to 2017. DEF will satisfy its additional reliability needs by building its NPGU in its updated Base Generation Plan, the Citrus County Combined Cycle Power Plant.

Q. When did DEF update its Base Generation Plan?

A. The Company continually reviews its resource plan as part of its on-going IRP process. This process did not end when the Company filed its 2013 TYSP with the Commission. That Base Generation Expansion Plan included the CR3 retirement and the CR1 and CR2 retirements, although at that time the CR1 and CR2 retirements were projected to occur in 2016. The 2013 Base Generation Expansion Plan also included the Suwannee unit retirements in 2018, and the oldest combustion turbine unit retirements, with the projected need for additional capacity between 2013 and 2022. To meet this additional capacity need, DEF at that time planned additional power purchases and the construction of smaller combined cycle power plants than the Citrus County Combined Cycle Power Plant in 2018 and 2020, subject to further

Company analysis of these options and the most cost-effective alternatives to meet the Company's additional generation capacity needs. Indeed, we always make clear in our TYSPs that fulfillment of the Base Generation Expansion Plan depends on, among other factors, changes in projected load growth, legislative and regulatory changes, permitting and licensing requirements, and cost and schedule changes.

After filing its 2013 TYSP with the Commission, the Company obtained additional clarity around the environmental requirements affecting CR1 and CR2 that led the Company to decide to pursue the modifications to its Integrated Clean Air Compliance Plan that I described above to continue to operate CR1 and CR2 until mid-2018. Additionally, as reflected in the 2013 Settlement Agreement, the Company decided to evaluate potential generation facility acquisitions and self-build generation options in addition to potential power purchases to meet the Company's near term needs for additional capacity. At the same time, the Company still planned to build a combined cycle generation plant in 2018, albeit a larger plant to meet load forecast changes and the modifications to the plan prior to 2018, subject to the determination that this was the most cost-effective alternative in the 2018 RFP in accordance with the Commission's Bid Rule.

All of these changes were taken into account in the Company's recently completed 2018 RFP and are reflected in the Company's current 2014 TYSP. The Base Generation Plan now includes the Citrus County Combined Cycle Power Plant as the NPGU.

Q. Did DEF take into account other, potential generation supply resources before selecting the Citrus County Combined Cycle Power Plant as the Next Planned Generating Unit?

A. Yes. DEF's plan takes into account its future supply of firm capacity from purchased power contracts, as well as its own existing and committed generating units that will be in service during the study period. DEF also examined alternative generation expansion scenarios when it identified the need for additional generation capacity in 2018 in its IRP process. Supply-side resources were screened to identify the most cost-effective generation resources, beginning with a wide range of industry options. DEF pre-screened the options that did not warrant more detailed cost-effectiveness analysis based on industry information and experience with the generation options and DEF's own information and experience with them. The screening criteria included costs, fuel sources and availability, technological maturity, generation capacity efficiency and availability, and overall resource feasibility within the Company's system.

Generation alternatives that passed the initial screening were considered viable generation capacity alternatives and were included in the next step of the IRP process. That step involved an economic evaluation of the generation alternatives in a computer model called Strategist. Strategist is an electric utility industry standard resource optimization program. Strategist models DEF's system and determines the combination or combinations of future resource additions that meet system reliability criteria while satisfying system constraints at the most cost-effective total production cost for DEF's system. The primary output of Strategist is the Cumulative Present Value Revenue Requirements ("CPVRR").

The most cost-effective supply-side resource or combinations of resources are evaluated and the various generation plans are ranked by system revenue requirements, or the CPVRR results. Strategist considers many tens or hundreds of thousands of resource combinations. Each of these resource combinations is ranked based on cost performance over both the planning period (20 years) and the study period which includes end effects. 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 models system behavior at an hourly level and allows for the input of a greater detail of operating constraints. DEF combines the production cost results of EPM with the fixed cost outputs from Strategist to create its final rankings. Generally, the generation plan with the lowest CPVRR over the study period is chosen as the Base Generation Plan. In this case, the updated Base Generation Plan includes the Citrus County Combined Cycle Power Plant as the NPGU.

Q. Did DEF evaluate demand-side programs to determine if they could replace or mitigate the need for the Next Planned Generating Unit in the Company's IRP process?

A. Yes. In a general manner, demand-side resources are evaluated in much the same manner as supply-side resources. Industry and Company information on potential demand-side resources are collected for evaluation. These potential demand-side resources are screened to eliminate resources that are in research and development and not commercially or technically viable at this time. Potential demand-side resources that are already available or otherwise in place, for example, through building code changes, and those that are not applicable to DEF customers are also eliminated in the screening process. Strategist is then up-dated with the cost and load impact parameters for the potential demand-side resources that survive the screening process. The Strategist model screens these demand-side resources on an individual basis against supply-side generation avoided units to determine the benefit or detriment to the DEF system from adding the demand-side resource to DEF's system. Strategist will calculate the benefits and costs for each demand-side resource and produce reports that provide the ratios for the Rate Impact Measure ("RIM"), Total Resource Cost Test ("TRC"), and the Participant Test. Cost-effective demand-side resources are implemented and included in the Strategist model to determine the Integrated Optimal Resource Plan that produces the Base Generation Expansion Plan.

Q. What were the results of your evaluation of demand-side resources as a potential replacement or mitigation for the need for additional generation resources in 2018?

A. There are no demand-side resources reasonably available to DEF to replace or mitigate the need for additional generation capacity in 2018 to meet the Company's reliability needs. DEF included the demand-side resources in its current Demand Side Management ("DSM") Plan, as modified by the Commission in Order No. PSC-11-

0347-PAA-EG, and, as further modified by administrative approval in 2012, in its model runs to determine the Base Generation Plan. These DSM programs extend through the end of this year when new DSM goals for the next ten years will be approved by the Commission in Docket No. 130200-EI and when subsequently DEF will submit proposed DSM programs to meet those goals for Commission approval. The Company assessed the projected cost, performance, viability, and cost-effectiveness of a wide range of dispatchable and non-dispatchable DSM programs and selected the DSM programs as the most cost-effective demand-side resources reasonably available to the Company. They do not replace or offset the need for additional supply-side generation resources in 2018.

Q. Did the Company consider the impact of potential future changes in the DSM program in its IRP process to determine its need for additional generation resources in 2018?

A. Yes. DEF has performed the IRP process evaluations necessary for the Commission's current DSM goals docket and, based on the results of those analyses, there is no reason to conclude that the Company's determination that it needs additional supply-side generation capacity in 2018 to meet its reliability needs will be affected by the outcome of that docket. Over the next ten years the Company's proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. All other things being equal, this change causes an increase in DEF's firm winter and summer peak demand and, therefore, further establishes the need for the Citrus County Combined Cycle Power Plant NPGU to meet DEF's reliability need in 2018.

DEF has successfully implemented cost-effective DSM programs for the past thirty years to reduce energy demand and energy consumption and avoid generation. Through 2011, DEF's Commission-approved DSM programs have resulted in over $1.2 billion in customer energy savings by achieving reductions in energy consumption of more than 5,000 GWh and demand savings of over 1,645 MW, effectively eliminating the need for the Company to build and operate approximately 18 peaking power plants. Substantial reductions in energy consumption and demand, therefore, already have been achieved in the Company's service territory, necessarily resulting in diminishing future energy consumption and demand reductions from more costly future energy efficiency programs and measures. The past success of the Company's DSM programs -- together 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 -- means that achieving the next incremental increase in energy efficiency and demand reduction is more difficult and more costly. The Commission recognized this in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs.

For these reasons, DEF expects that its proposed DSM goals for the next ten years will be accepted by the Commission. As a result, the proposed DSM goals will have no impact on the Company's reliability need in 2018. There simply are no DSM measures that can offset the need for additional generation capacity beginning in 2018, certainly not any that can be implemented at a cost effective rate that is acceptable for DEF's customers.

V. NEXT-PLANNED GENERATING UNIT: CITRUS COUNTY COMBINED CYCLE POWER PLANT.

Q. Please explain the Company's Base Generation Expansion Plan.

A. Through the Company's IRP process we developed the Company's Base Generation Expansion Plan. The Plan includes the addition of the Suwannee Simple Cycle project, involving the construction of two new, highly-efficient, combustion turbine units at the existing Suwannee power plant site in 2016, and the Hines Chillers Power Uprate project at the HEC in 2017. The Plan also includes the construction of the Citrus County Combined Cycle Power Plant at the new Citrus County site adjacent to the CREC as the NPGU in 2018. The Citrus County Combined Cycle Power Plant will be a state-of-the-art combined cycle power plant. The Plan also calls for the addition of another combined cycle power plant at an undesignated site in 2021. DEF's present Determination of Need Petition, its separate petition to determine the most cost-effective alternative to meet its capacity needs prior to 2017, and its April 2014 TYSP are all consistent with the Company's IRP process and this Base Generation Expansion Plan.

Q. What impact will the addition of the Citrus County Combined Cycle Power Plant have on DEF's Reserve Margin reliability criterion?

A. As shown in Exhibit No. ___ (BMHB-3), the addition of the Citrus County Combined Cycle Power Plant will increase DEF's summer peak Reserve Margin to about 20.4 percent in 2018 and 23.6 percent in 2019. The Citrus County Combined Cycle Power Plant allows DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin by 2018 and beyond 2018.

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 generation capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. Dispatchable DSM demand-side resources reduce the peak customer load, when needed. However, based on the Company's prior experience implementing its dispatchable demand-side resources, such resources cannot be used as often or as long as physical generation reserves without eventually affecting customer participation levels in the dispatchable DSM programs. In other words, customers are less willing to accept service under the dispatchable DSM demand-side resource programs for lower rates when interruptions in electric service increase in frequency or duration. For this reason, additional physical reserves are a more reliable power supply than the consent of customers to interruptions in electric service for reduced tariffs resulting from their participation in dispatchable DSM programs. Based on projected load growth, the addition of the Citrus County Combined Cycle Power Plant will increase the Company's share of physical reserves to approximately 60 percent of total summer reserve capacity, including DSM, in the summer of 2018. DEF believes this is an appropriate level of physical reserves because it provides a cost effective balance of the need for physical reserves to respond to reliability needs under adverse load and capacity conditions and the availability of dispatchable load control to respond to short term upsets and peak shaving events.

Q. Why has DEF chosen natural-gas fired, combined cycle generation to install?

A. Our CPVRR economic analyses favor natural-gas fired, combined cycle generation to meet our generation reliability needs. DEF has projected the need for combined cycle generation capacity in its 2013 and 2014 TYSP filings, and natural-gas fired, combined cycle generation has been a competitive generation resource for Florida for many years.

One reason for this is that there are few, large-scale generation capacity technologies available to Florida utilities that can produce power on a base load basis. Increasing environmental emission regulations and permitting requirements have made utility-scale coal-fired, steam generation increasingly costly to build and operate, and difficult to impossible to site and permit in Florida. Barring advances in coal-fired generation emission-control and carbon-capture technologies that are not yet commercially available, there is no reason to believe at this time that an electric utility can obtain a need determination and the necessary permits to build a new coal-fired, steam generation plant in Florida.

Likewise, DEF is no longer pursuing new nuclear power generation in Florida, despite the relative cost-effectiveness of new nuclear generation in a carbon-constrained future regulatory environment and the fuel diversity benefits that nuclear generation provides DEF and the State of Florida. As a result, while DEF continues to regard new nuclear generation as a viable, future base-load generation resource for Florida, the Company's decision to build new nuclear generation in the future depends on, among other factors, future energy needs, nuclear development and construction cost, future carbon regulation, future natural gas prices, and the current and future legislative and regulatory provisions for cost recovery for nuclear development and construction costs.

As a result, natural-gas fired, combined cycle generation is the most economic and qualitatively attractive large-scale generation technology for DEF and the State of Florida at this time and for the foreseeable future. This technology, however, is by no means simply a "default" generation choice. Another reason to choose this generation technology is that improvements in the technology with its wide spread development and use the past two decades have increased its generation efficiency, lowering the cost per unit of fuel for this technology, and making the combined cycle generation technology an even more cost-effective producer of energy. Exhibit No. ___ (BMHB-5), which contains a comparison of the cost efficiency of the combined cycle generation technology compared to other commercially available, utility-scale generation technologies, demonstrates the cost effectiveness of combined cycle generation at high capacity factors in baseload and intermediate service.

Q. Is DEF becoming too dependent on natural gas for its generation?

A. No. Current economics overwhelmingly favor natural gas units, and for good reason. As demonstrated above and in Exhibit No. ____ (BMHB-5), natural gas-fired, combined cycle generation is a highly efficient, cost-effective source of generation capacity. In addition, there are abundant natural gas resources available in the United States and North America. These natural gas resources ensure a long term natural gas supply at economically beneficial prices for electric power generation in this country and, in particular, here in Florida.

Q. Why does the Company believe there is an adequate, long-term supply of natural gas available at economically beneficial prices for the Citrus County Combined Cycle Power Plant?

A. Recent technological improvements in gas drilling, colloquially called "fracking," have led to unconventional shale gas developments that now provide access to gas supplies that simply did not exist as few as ten years ago. Exhibit No. ___ (BMHB-6) shows the location of the unconventional shale gas developments and major gas pipelines in the Southeast United States. As demonstrated in Exhibit No. ___ (BMHB-6), there are several Southeast shale gas plays with abundant shale gas. The widespread employment of gas fracking technology ensures that shale gas plays will provide an abundant supply of natural gas for electric power generation over the thirty five year planning period used to determine the cost-effectiveness of the Citrus County Combined Cycle Power Plant. The availability of these gas resources and their impact on the future price of natural gas for future gas power production are explained in more detail by Mr. Delehanty in his direct testimony.

While the focus in production and transportation development has been on shale gas sources, there remains abundant conventional gas resources in commercial development or available for future development in North America. Again, advances in drilling technology and efficiencies have actually expanded the ability to produce gas from these conventional resources. Exhibit No. ___ (BMHB-7) to my direct testimony depicts the recent, current, and future production from both conventional and unconventional North American natural gas resources. While shale gas production is expected to grow at the fastest rate, conventional gas resources are also expected to increase production over the next 25 years. Conventional natural gas production in North America will continue to be a long-term gas supply resource for electric power generation in this country.

DEF plans to access both the conventional and unconventional gas supplies for the Citrus County Combined Cycle Power Plant. DEF has a gas transportation contract for the Citrus County Combined Cycle Power Plant with Sabal Trail. Sabal Trail is building a new, third natural gas pipeline into the State of Florida. Exhibit No. ___ (BMHB-8) is a map showing the location of the Sabal Trail natural gas pipeline. As demonstrated on this map, the Sabal Trail pipeline extends from Transcontinental Pipe Line Company Compressor Station 85 ("Transco Station 85") in Choctaw County, Alabama to a planned gas transportation interconnection hub in Orange County Florida. This hub will provide interconnection between Sabal Trail and the existing FGT and Gulfstream pipeline infrastructure. This will provide access to Sabal Trail supplied gas throughout the State. Transco Station 85 provides Sabal Trail access to the abundant, unconventional shale gas supplies in the Southwestern United States. This can be seen by comparing the location of the Sabal Trail pipeline connection at Transco Station 85 and its other pipeline connections on the map in Exhibit No. ___ (BMHB-8) to the map of the unconventional shale gas plays in Exhibit No. ___ (BMHB-6). Sabal Trail, therefore, can draw from both conventional and unconventional natural on-shore natural gas supplies. When DEF adds the Citrus County Combined Cycle Power Plant to its system and connects that Plant with Sabal Trail DEF adds natural gas fuel supply diversity to its system. The fuel supply plan for the Citrus County Combined Cycle Power Plant is further explained by Mr. Patton in his direct testimony.

Q. Will DEF have access to other natural gas pipelines for gas supply to the Citrus County Combined Cycle Power Plant?

A. Yes. DEF will also be able to access the existing Florida Gas Transmission Company ("FGT") pipeline for the Citrus County Combined Cycle Power Plant. The location of the FGT pipeline and the Gulfstream pipeline, the other existing natural gas pipeline into the State of Florida, in relation to the Sabal Trail pipeline is also depicted in Exhibit No. ___ (BMHB-8) to my direct testimony. This connection is also explained in more detail by Mr. Patton in his direct testimony in this proceeding. This ability to access the FGT pipeline provides DEF additional fuel supply diversity by making more conventional gas supplies in the Gulf of Mexico and on the coast available to the Company for the Citrus County Combined Cycle Power Plant.

Q. Does natural gas supply diversity provide sufficient fuel diversity?

A. Yes. The abundant supply of unconventional natural gas resources is a significant recent development that provides electric utilities like DEF with natural gas supply diversity to achieve one of the primary objectives of fuel diversity, namely, ensuring that fuel is readily available at a cost-effective price. Access to both these unconventional natural gas resources and conventional natural gas resources also achieves the second primary objective of fuel diversity, that is, ensuring a reliable fuel supply in the event of gas supply interruptions. The natural gas fuel supply diversity means the Company can still generate electricity economically in the event of such interruptions to one or more of the fuel supply resources available to DEF for the Citrus County Combined Cycle Power Plant. DEF, therefore, has reasonably provided for the benefits of fuel diversity with the construction and operation of the Citrus County Combined Cycle Power Plant on its system.

Also, DEF still has substantial base load coal-fired, steam generation capacity on its system. DEF recently retro-fitted the CR4 and CR5 coal-fired, steam generation facilities to meet existing and future environmental emission regulations. CR4 and CR5, accordingly, will continue to provide over 1,400MW of summer (and winter) base load generation capacity to DEF customers. This coal-fired generation provides DEF additional fuel diversity.

Finally, there simply are no other commercially available, utility-scale generation facility resources that can feasibly be added to DEF's system to meet DEF's generation capacity needs. As I explained above, building new coal-fired generation or nuclear generation capacity in Florida is not feasible at this time given environmental constraints and the existing legislative and regulatory framework. There also is a limited outlook for cost-effective renewable resources to meet DEF's reliability needs.

Q. Why are there limited renewable resources available to meet DEF's reliability needs?

A. Renewable resources such as wind, solar, and bio-mass are not commercially available on a utility-scale for generation capacity at a cost-effective price. DEF has held open a Request for Renewables ("RFR") for renewable generation resources for years and DEF has not received a utility-scale, commercially viable solar or wind proposal that has actually achieved commercial operation. In addition, DEF's 2018 RFP was open to all proposals for additional generation capacity and the only proposals DEF received were for gas-fired generation (with the exception of a small, existing municipal waste renewable generation facility). DEF will continue to solicit renewable projects through its RFR, however, large scale, commercially viable and economic generation capacity renewable projects cannot be reasonably expected at this time.

Q. Are there environmental benefits to adding the Citrus County Combined Cycle Power Plant to DEF's system?

A. Yes. A combined cycle facility fueled by natural gas is the cleanest and most efficient fossil-fueled generation. For example, there are virtually no sulfur dioxide (SO_2) emissions. Nitrogen oxide (NO_x) emissions, with low NO_x burners installed, are approximately one tenth the level of coal-fired, steam generation NOx emissions. These and other environmental benefits from adding the Citrus County Combined Cycle Power Plant to our system are explained in more detail in the testimony of Amy Dierolf in this proceeding.

In addition to providing needed baseload capacity in a cost effective and environmentally responsible manner, during off-peak periods, the more efficient generation of the Citrus County Combined Cycle Power Plant will displace generation from other less efficient and less well controlled sources, reducing DEF's overall portfolio emissions. The proposed Citrus County Combined Cycle Power Plant will provide cleaner air for Florida compared to other alternative, commercially feasible, utility-scale generation technologies. The Citrus County Combined Cycle Power Plant will help the Company comply with current environmental regulations, as well as prepare the Company to meet more stringent regulations that may be enacted in the future.

VI. DEF's 2018 RFP.

Q. Please describe DEF's 2018 RFP.

A. In accordance with the Commission Bid Rule, DEF issued the 2018 RFP on October 8, 2013, soliciting proposals for other generation capacity resources that might prove superior as a supply-side alternative to the Company's Citrus County Combined Cycle Power Plant NPGU. The 2018 RFP is included as an appendix to the Need Study included as Exhibit No. ___ (BMHB-1) to my direct testimony.

In our 2018 RFP, we explained that we had identified the Citrus County Combined Cycle Power Plant as our NPGU, and we invited interested parties to make alternative proposals that offered superior value, based on price and non-price attributes, to the Company's customers. We sought reliable, dispatchable, financially and technically sound capacity and energy proposals to meet DEF's reliability need in 2018. We evaluated all proposals by systematically following a structured, orderly evaluation process, which we identified in the 2018 RFP, along with the criteria by which we evaluated the proposals.

Q. Briefly, what were the results of the RFP?

A. We received six proposals in addition to the Company's self-build proposal for the Citrus County Combined Cycle Power Plant NPGU. Bidders also included five alternatives to their base proposals. None of these proposals met the Company's reliability need for 1,640 MW of summer generation capacity in the year 2018, with a minimum of 820 MW in service no later than May 1, 2018 and the balance of generation capacity in service no later than December 1, 2018. None of the proposals individually met the request for 820 MW in service by May 1, 2018 and in fact, all six proposals combined did not meet the Company's reliability need for generation capacity in 2018. This reliability need was clearly explained to potential bidders in the 2018 RFP.

Because none of these six proposals individually or collectively met DEF's reliability need in 2018, DEF reasonably could have rejected the proposals for failure to comply with the 2018 RFP without further evaluation and selected the self-build proposal for the Citrus County Combined Cycle Power Plant NPGU. DEF decided to continue its evaluation of these six proposals, however, to see if there was any combination of them that, individually or collectively with other, undeveloped generic Company power plants, provided customers a more cost effective supply-side generation alternative to the Citrus County Combined Cycle Power Plant NPGU. These combinations, or resource combination scenarios, were quantitatively and qualitatively evaluated against the Citrus County Combined Cycle Power Plant.

That evaluation, as I describe in more detail below, demonstrated that the Citrus County Combined Cycle Power Plant NPGU is the most cost-effective supply-side generation capacity to meet the Company's reliability need in 2018. The Citrus County Combined Cycle Power Plant is approximately $477 million less expensive than the most realistic least-cost, third-party proposal resource combination scenario. We further performed sensitivity analyses, in which we assumed either a high gas price forecast case or a zero carbon cost ("CO2") price case, and, in all these cases, the Citrus County Combined Cycle Power Plant is the least cost alternative. Our evaluations demonstrate that the selection of the Citrus Country Combined Cycle Power Plant is the right choice for our customers.

Q. Were there any other issues with the 2018 RFP bids besides their failure to meet the Company's reliability needs identified in the 2018 RFP?

A. Yes. There were non-conformance issues or risks associated with the 2018 RFP threshold requirements or technical criteria associated with each of these six 2018 RFP proposals. These are explained in more detail below or in the Need Study.

Despite these issues and risks, DEF also determined that, given the limited number of 2018 RFP bids DEF received, it would consider all bids in the preliminary economic evaluation and detailed evaluations described in the 2018 RFP. These bid non-conformance issues or risks were considered in the Company's qualitative assessment of the non-price attributes of the bid proposals in the detailed evaluations.

Q. Please describe the 2018 RFP.

A. The 2018 RFP has four key components. The first component is the Solicitation Document, which outlined DEF's need for generating capacity, the objectives of the 2018 RFP, the Company's NPGU, DEF's system specific conditions, and a schedule of key dates in the 2018 RFP process. The document also addresses DEF's requirements for the submission of bids, and it described the criteria that DEF would use to compare and evaluate the price and non-price attributes of the proposals, consistent with the requirements of the Commission Bid Rule.

The second key component was the Response Package. The Response Package contained a description of the information bidders were to provide in their proposals. It defined the required organizational structure and contents of any submitted proposal and it contained instructions on how to complete the schedules (or forms) provided to the bidders. The third key component consisted of the Schedules (Microsoft Excel worksheets) that bidders were required to use to provide data, including pricing, to DEF.

The fourth key component was the key Terms and Conditions of a purchased power agreement in the event that a bid proposal was selected as the most cost-effective generation option to meet DEF's reliability need. Also, consistent with the Bid Rule, a copy of DEF's most recent TYSP, the 2013 TYSP, was attached to the 2018 RFP.

Q. Did you open the 2018 RFP up to all potential participants and proposals?

A. Yes, DEF invited all creative, innovative, or inventive responses that met DEF's fundamental requirement for firm supply-side, dispatchable capacity and energy in 2018. DEF, in fact, eliminated the planned minimum capacity requirement in the 2018 RFP at the request of a potential bidder at the 2018 RFP pre-issuance meeting. DEF was, therefore, willing to consider and did consider firm, dispatchable generation capacity proposals of any size in combination with other proposals or in resource portfolios with generic Company generation units to meet its generation capacity reliability need in 2018.

Second, to provide bidders more flexibility, we allowed delivery terms for proposals between 15 and 35 years, despite DEF's need for a long-term supply of reliable generation capacity. Third, we allowed potential bidders to submit up to two variations in their bid proposals at no additional cost. Fourth, we allowed potential bidders to provide generation capacity up to sixty days early, before DEF's capacity was needed. Finally, we told the bidders we would allow them to propose a fuel tolling arrangement whereby DEF would be responsible for acquiring fuel for the proposed project.

Q. **What was the first step in the 2018 RFP process?**

A**.** The 2018 RFP process started with our announcement that we were going to be issuing an RFP for generating alternatives. We provided public notice of the RFP issuance on September 24, 2013. The public notice was published in newspapers of state and national circulation, and in trade publications and periodicals, consistent with the Bid Rule. These publications were Megawatt Daily, SNL, the Tampa Tribune, the Orlando Sentinel, Energy Biz, and Power Engineering. The notice provided a general description of the Company's NPGU, the name and address of the contact person from whom to request a 2018 RFP package, the Company's 2018 RFP web site address where the 2018 RFP package also could be obtained, and the schedule of critical dates for the 2018 RFP process. A press release was also published and referred to in articles by a number of news services, both in print and on-line, including the Tampa Bay Times, the Wall Street Journal, Power Engineering, Yahoo Finance and others.

Q. When was the 2018 RFP package first available on the 2018 RFP web site.

A. Draft versions of the 2018 RFP Solicitation Document and the Response Package were available on September 24, 2013. Drafts of the 2018 RFP documents were made available to potential applicants so a more informed discussion about the RFP could take place at the 2018 RFP Pre-Issuance meeting.

Q. Was there a contact person for any questions, clarifications, or requests for additional information about the 2018 RFP?

A. Yes. I was the DEF 2018 RFP contact and my contact information was provided to potential bidders in the draft 2018 RFP solicitation document and on the 2018 RFP website. DEF also retained Alan Taylor with Sedway Consulting, Inc. as an independent monitor/evaluator ("IM/E") for the 2018 RFP. His contact information was also provided to potential bidders in the draft 2018 RFP solicitation document and on the 2018 RFP website. Potential bidders were asked in the 2018 RFP solicitation to contact both of us with any questions or comments regarding the 2018 RFP.

Q. What was the role of an Independent Monitor and Evaluator for the 2018 RFP?

A. DEF retained an independent monitor to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP solicitation documents were clear, fair, and consistent with the Commission Bid Rule. DEF also retained an independent evaluator to ensure that DEF's evaluation of the proposals received in response to the 2018 RFP was fair and impartial and that the Company's selection of the most cost-effective proposal to meet DEF's reliability need in response to the 2018 RFP was reasonable.

Q. Why was Mr. Taylor retained as the Independent Monitor and Evaluator for the 2018 RFP?

A. Mr. Taylor and his company, Sedway Consulting, have considerable industry expertise and experience with RFPs for supply-side generation. Mr. Taylor and Sedway Consulting have served as the independent monitor and evaluator for utility solicitations for capacity, energy, or both in California, Colorado, Georgia, Iowa, Illinois, Minnesota, North Carolina, South Dakota, and Texas. In addition, Mr. Taylor has provided independent monitor or evaluator services for several RFPs in Florida, including prior RFPs by DEF's predecessors. Mr. Taylor has testified in several Commission need proceedings regarding these RFPs pursuant to the Commission Bid Rule. Mr. Taylor also provided input to the Commission with respect to the development of the Commission's current Bid Rule. More detail on Mr. Taylor's experience as an independent monitor or evaluator and his expertise with respect to utility capacity and energy solicitations is provided by Mr. Taylor in his direct testimony in this proceeding.

Q. What was the Pre-Issuance meeting and when was it held?

A. The Pre-Issuance meeting was held on October 2, 2013 at the Tampa Marriott Westshore located at 1001 North Westshore Boulevard. Potential participants were also allowed to participate in the Pre-Issuance meeting via conference call. The purpose of the Pre-Issuance meeting was to discuss the requirements of the 2018 RFP. The meeting consisted of a presentation that I made covering the objectives of the 2018 RFP, the types of proposals allowed, the 2018 RFP package, the 2018 RFP process, and our requirements for potential bidders. Throughout the presentation, questions were invited, and when asked, answers were provided. All questions and answers were later posted on the 2018 RFP web site. The pre-issuance meeting was recorded by a court reporter and the transcript of the pre-issuance meeting and a copy of the presentation were posted to the 2018 RFP web site for potential bidders.

Q. Did you make any changes to the RFP based on the Pre-Issuance meeting?

A. Yes, we did. As I explained above, we eliminated a minimum generation capacity limit for the proposals in response to the 2018 RFP at the request of a potential bidder during the Pre-issuance meeting. Other clarifications to some of the wording in the 2018 RFP documents were made based on questions that were asked or comments that were expressed by the participants at the Pre-Issuance meeting.

Q. When did DEF actually issue the RFP?

A. The 2018 RFP was issued on October 8, 2013 and it was available for downloading from the 2018 RFP web site. DEF allowed any interested visitor to the site to download the RFP in PDF format. Entities interested in receiving the editable versions of the RFP and the response package were asked to register. DEF did not refuse any requests to register. Downloads of the PDF version of the RFP were not monitored. Twenty-seven (27) different entities registered to participate in the RFP and receive the editable RFP documents.

Q. Did DEF hold a Bidders' Meeting for the 2018 RFP?

A. Yes, a Bidders' Meeting was held on October 18, 2003, also at the Tampa Marriott Westshore on Westshore Boulevard in Tampa, Florida. The purpose of the Bidders' Meeting was to provide interested parties the opportunity to ask questions and seek additional information or clarification about the 2018 RFP documents and solicitation process. Again, potential participants were allowed to attend by conference call. I made a brief presentation similar to the one I made at the Pre-Issuance meeting, summarizing the 2018 RFP process and the 2018 RFP requirements. Bidders were encouraged to submit questions ahead of time, during the presentation, and after the Bidders' Meeting. All questions and the corresponding answers were posted on the 2018 RFP web site, including the additional questions and answers after the Bidders' Meeting. The Bidders' Meeting was also recorded by a court reporter and the transcript of the Meeting and a copy of the presentation were posted to the 2018 RFP web site for potential bidders.

Q. Did DEF receive proposals in response to the 2018 RFP?

A. Yes. We received six proposals with five variations from third-party bidders on December 9, 2013. The Company's self-build team also submitted a proposal for the Citrus County Combined Cycle Power Plant NPGU on the same date.

Q. What kinds of proposals did you receive?

A. All but one of the bidder proposals were Existing Unit Proposals. There was one bidder New Unit proposal and the self-build team proposal for the Citrus County

Combined Cycle Power Plant. The proposals varied in length, but none of them equaled the expected service life of the Citrus County Combined Cycle Power Plant NPGU of 35 years, which was the study period in the RFP evaluation process. All but one of the proposals would be fueled primarily with natural gas and the other proposal was a small, existing resource recovery facility. The start date for all but one of the proposals was at least by May 1, 2018 with some before that date. A summary of the bidder proposals including a list of the names of the bidders and a description of the size and type of generation in the proposal can be found in a confidential appendix to the Need Study.

VII. THE 2018 RFP EVALUATION PROCESS.

Q. Did DEF describe the evaluation process it was going to use in the 2018 RFP solicitation documents?

A. Yes. The 2018 RFP solicitation document described in detail the evaluation process we planned to use in the evaluation of the proposals in response to the 2018 RFP.

Q. Please briefly describe the evaluation process.

A. The process, of course, is described in detail in the 2018 RFP solicitation document itself, but it is shown in flowchart form in Exhibit No. ___ (BMHB-9) to my direct testimony. This is the same flowchart that was included in the 2018 RFP solicitation document.

Briefly, the first step in the RFP evaluation process was screening for Threshold Requirements. In this step, the proposals were reviewed to ensure they met the basic RFP information requirements. The Threshold Requirements were provided in a table in the 2018 RFP solicitation document so that the potential bidders could check to ensure their proposals fulfilled these requirements. Proposals that did not meet the Threshold Requirements were subject to elimination from further evaluation.

The next step was the preliminary economic screening and screening for compliance with the 2018 RFP Minimum Technical Requirements. The purpose of the preliminary economic screening was to narrow the number of proposals for the more detailed evaluation analyses by eliminating any proposals that were much higher in cost relative to other proposals in the RFP evaluation process. The proposals were screened based on the fixed, variable, and other payments. Proposals that were significantly higher in cost compared to other proposals could be eliminated from further evaluation. The pricing parameters for this preliminary economic screening were made available to potential bidders in a table in the 2018 RFP solicitation document.

In this step DEF also determined if bidders complied with the Minimum Technical Requirements. The Minimum Technical Requirements were also provided to bidders in a table in the 2018 RFP solicitation document. DEF included a description of each of these non-price attributes, as well as the Company's preferences with regard to the attributes. The purpose of the Minimum Technical Requirements was to assess the feasibility and viability of each proposal.

The third step was selection of a short list for the initial and final detailed evaluations in step four of the 2018 RFP evaluation process. In the initial and final detailed evaluations, proposals included on the short list would be compared to DEF's self-build alternative, the Citrus County Combined Cycle Power Plant NPGU. Proposals were subject to more detailed economic and qualitative assessments, and transmission cost impacts would be incorporated into the analyses. Scenario and sensitivity analyses would also be conducted, if deemed appropriate based on the proposals submitted.

The next two steps were selection of a final list of bidders for potential contract negotiation. In the event that the Citrus County Combined Cycle Power Plant was found to be clearly superior to the proposals, a final list would not be selected. We also anticipated an announcement of a final decision after contract negotiations, but that was dependent on the results of the evaluation and would not take place if the Citrus County Combined Cycle Power Plant was found to be a more cost-effective option for customers than the other proposals.

A. THRESHOLD REQUIREMENTS SCREENING.

Q. Was this evaluation process followed?

A. Yes. We began our bid evaluation process with the threshold screening. We evaluated all of the proposals against the Threshold Requirements identified in Figure III-2 of the 2018 RFP solicitation document and shown in Exhibit No. ___ (BMHB-10). As I explained above, the Threshold Requirements represent the minimum requirements that all proposals are required to meet to be evaluated.

Some examples of Threshold Requirements are general requirements, such as the proposal being received on time, the submittal fee being included, and the power being available for delivery by May 1, 2018. Others include operating thresholds, such as operating the project to conform to DEF voltage and frequency control requirements, the agreement by the bidder to coordinate maintenance scheduling, and the bidder demonstrating control of the site. Bidders were also required to agree to key terms and conditions of any potential contract or propose revised terms and conditions for DEF's review and possible acceptance. The threshold screening provided a "sanity check" of the proposals by ensuring that DEF had everything it asked for and needed to perform its evaluation analyses.

Q. Were the key terms and conditions for any contract with a potential bidder?

A. The 2018 RFP solicitation document included a set of terms and conditions for a potential power purchase agreement that were critical to DEF in Attachment A to the 2018 RFP solicitation document. Bidders were not required to agree to all the terms, but were instructed to mark the terms and conditions for any changes that they would like to make. We would then evaluate the proposals based on the extent to which the proposed deal was contingent on changing the key terms and conditions. This would also provide a starting point for contract negotiation if a bidder were selected to the final list. The terms and conditions are too numerous to describe in my testimony but they cover subjects one would customarily expect to see addressed in a power purchase agreement, and, as I mentioned, they were provided to the bidders as an integral part of the 2018 RFP solicitation document.

Q. How did you evaluate the contractual terms offered for each proposal?

A. In the 2018 RFP solicitation document, DEF reserved the right to consider any unique flexibility provisions offered by a bidder. Examples typically include contract options such as buyout provisions, or options to extend the contract, among others. In this RFP, alternate contract structures were offered as variations to base bids and included options to acquire certain units and varying contract lengths. DEF evaluated these as part of the economic screening. Evaluation of any changes to the proposed terms and conditions was deferred until conclusion of the economic screening.

Q. What were the results of the threshold screening?

A. None of the proposals initially passed the Threshold Requirements screening process without any deficiencies. All of the proposals required at least some clarification. DEF explained in the 2018 RFP solicitation document that, at its discretion, DEF would work with the bidders to clarify their proposals if they did not pass the threshold screening based on DEF's initial review. We, in fact, went back to the bidders with questions in an effort to help them resolve the deficiencies in their proposals and to make sure we had everything we needed to conduct a thorough evaluation of the bids. Despite some continuing, existing and potential non-conformance issues with certain bidder proposals, we did not eliminate any proposal for failure to fully conform to the Threshold Requirements. The bidders attempted to provide additional clarification or information in response to DEF's questions. DEF decided to address the existing and potential non-conformance issues in the

Company's qualitative assessment of the risks associated with the bidder proposals in the consideration of the non-price attributes of the proposals.

Q. Was this approach acceptable to the independent monitor and evaluator?

A. Yes. Before we made this decision we discussed it with Mr. Taylor. Mr. Taylor agreed that this was a fair approach to the evaluation process even though DEF had the right under the 2018 RFP solicitation document to disqualify the non-conforming proposals from further evaluation.

B. INITIAL ECONOMIC SCREENING ANALYSIS.

Q. What did you do next in the 2018 RFP evaluation process?

A. We performed our initial economic screening analysis. The screening analysis compared the proposals to each other in terms of $/kW-year, based on the total prices proposed by the bidders and an assumed capacity factor. As I explained above, the purpose of the initial economic screening was to get a perspective of the relative economics of the proposals compared to each other and to potentially eliminate proposals that were way out of line in terms of cost to the other proposals.

Q. What capacity factor did you assume for your initial economic screening analysis?

A. We assumed a capacity factor of 70 percent. This capacity factor was assumed because this was the expected capacity factor for the Citrus County Combined Cycle Power Plant.

Q. What was the result of your analysis?

A. The evaluated costs of all the proposals were within a reasonable range of each other. None of the proposals were so far out of line compared to the other proposals that they were eliminated from further analysis.

C. TECHNICAL EVALUATION.

Q. What was the next step in your evaluation of the proposals received in response to the 2018 RFP?

A. The next step was the Technical Evaluation. In this evaluation we assessed the non-price attributes of the proposals by evaluating the quality of the proposals from a technical perspective. We used the Technical Evaluation to help us get to a potential Short List of proposals for further, more detailed economic and qualitative evaluation by ensuring that all the proposals that went to the potential Short List were technically viable. The Technical Evaluation addressed the Minimum Technical Requirements, which were provided in the 2018 RFP solicitation document and are shown in Exhibit No. ___ (BMHB-11) to my direct testimony.

The Minimum Technical Requirements were the necessary technical elements of a proposal. They were the components, or characteristics, the proposals had to have to move forward in the evaluation process. The Minimum Technical Requirements fell into five categories: Environmental; Engineering and Design; Fuel Supply and Transportation Plan; Project Financial Viability; and Project Management Plan. The Minimum Technical Requirements are the most important non-price attributes of generation supply alternatives to DEF. Failure to meet one of the Minimum

Technical Requirements was grounds for disqualification of the proposal from further consideration in the evaluation process.

Q. Can you explain why the Minimum Technical Requirements are important to DEF?

A. Yes. I will start with the environmental requirements. The two requirements in the environmental category, that a preliminary environmental analysis had been performed and that a reasonable schedule for securing permits was presented to DEF, applied only to New Unit Proposals. The purpose of these requirements was to ensure that, to the greatest extent possible, the bidder for the proposed project could obtain the necessary environmental permits. We assessed the bidder's plan to obtain the necessary land use and environmental permits, including a water supply, for the proposed project, based on our extensive experience with obtaining permits for similar projects. This requirement was important to DEF's determination that the bidder could bring the proposed unit on-line on time.

There were also two requirements in the engineering and design category. The purpose of these requirements was to determine if the technology for the New Unit and Existing Unit Proposals was viable from an engineering and operations perspective. The bidders had to provide an operation and maintenance plan indicating the project would be operated and maintained in a manner that satisfied the bidders' contractual commitments. The bidders also had to demonstrate the project technology would be able to achieve its operating targets. For example, we considered the guarantee the bidder offered for the availability of the unit; that is, what percentage of time the bidder would guarantee that the unit would be available if we called on it. Specifically we did this by ranking the bidders based on the equivalent forced outage rate ("EFOR") they offered to guarantee.

We also evaluated each proposal to determine the operational criteria for the proposed unit, including, among others: Minimum load; Start time; Ramp rate; Maximum starts per year; Minimum run-time constraint; Minimum down-time constraint; and Annual operating hours limit. In general, these attributes measure the flexibility of the proposed unit to operate in ways that respond to changes in demand. We accordingly evaluated the proposed units with respect to how long it would take to get the proposed unit started, how long it would take to get the unit up to the desired output level, the number of times in a year the unit could be started and stopped, the minimum amount of time the unit would have to run once it was started, the amount of time the unit had to be off-line once it was shut down, and the number of hours in a year the unit could operate.

Q. What about fuel supply and transportation, why was that a Minimum Technical Requirement?

A. Bidders of New Unit and Existing Unit Proposals had to provide a preliminary fuel supply plan that described the bidder's plan for securing fuel supply and transportation for delivery to the project. Fuel supply and transportation, of course, are absolutely essential for any new or existing generation unit and a key cost factor in any economic analysis. We evaluated the fuel supply and transportation plans in the proposals based on, among other factors, the location of the plant; whether the plant was connected through a local distribution company ("LDC"); whether backup fuel was available; and, if so, how much backup fuel storage was available.

Alternatively, bidders had the option to propose a fuel tolling arrangement whereby DEF would be responsible for acquiring fuel for the Proposal unit. All bidders with the exception of the municipal waste proposal opted for the fuel tolling arrangement. Each of the natural gas fired bid proposals provided information on existing or expiring gas transportation contracts and/or gas supply infrastructure. This information was used in the evaluation of the proposals.

Q. What was the purpose of the financial viability Minimum Technical Requirement?

A. The purpose of the project financial viability Minimum Technical Requirement was to ensure the bidder had the financial backing to construct and/or operate the project through the term of the proposal. For New Unit Proposals, evidence had to be provided that demonstrated the project would be financially viable. All proposals had to demonstrate that the bidder would have sufficient credit standing and financial resources to satisfy its contractual commitments. We focused on the bidder's financial capability and credit. If the bidder was proposing to obtain project financing for its proposal, we would focus on the financial viability of the proposal. If the bidder indicated it would be providing equity to the project or would be self-financing the project, we would also assess the bidder's ability to provide the required equity or financing.

Q. What was the purpose of the final Minimum Technical Requirement?

A. The final component for the Minimum Technical Requirements applied to New Unit Proposals only. Bidders of New Unit Proposals had to submit a construction management plan to show that the project could be built in time to serve DEF's reliability need. We evaluated the likelihood of the project coming on line on time by evaluating the developer's planned permitting, licensing, and construction milestone schedules based on our extensive experience with developing and constructing similar projects. We also considered the bidder's experience in successfully developing and operating a project of the magnitude proposed.

Q. How were proposals evaluated on the Minimum Technical Requirements?

A. Each proposal was evaluated on each requirement on a "Pass/Fail" or "Go" / "No Go" basis. As discussed above and in the 2018 RFP solicitation document, failure to demonstrate conformance with the Minimum Technical Requirements was grounds for disqualification. Failing to meet a Minimum Technical Requirement should result in the elimination of a proposal from further consideration in the evaluation process because it doesn't meet a minimum standard for a good project. That is, a good project, in DEF's view, is one where there is a high probability that the necessary permits, approvals, financing, and other factors required to build and/or operate the project can be obtained or implemented in time to serve the reliability needs of DEF's customers and continue to serve them over the term of the proposed contract.

For most of the Minimum Technical Requirements, the proposals were reviewed to see if they had the required documents, schedules, or plans. For example, the project management plan required the bidders to provide a critical path diagram and schedule for the project that specified the items on the critical path and demonstrated that the project would achieve commercial operation by May 1, 2018. For requirements such as this, they either provided the information (and it was judged as acceptable), in which case they would pass; or they didn't provide the information (or it was deemed unacceptable), in which case they would fail. The evaluation teams used their years of knowledge and technical expertise to determine if the information provided was valid.

Q. Who evaluated the Minimum Technical Requirements?

A. We established separate teams staffed with personnel with expertise in the areas of development and construction, engineering operations, environmental, financial viability, fuel, key terms and conditions, and transmission to review the proposals. Each of the teams received the executive summaries of the proposals and only those portions of the proposals that dealt with its area of expertise. Only the economic evaluation team had access to the pricing proposals, since the other technical evaluators did not need to know the pricing proposals to perform the evaluation of the proposals on their technical merits. Thus, the technical evaluations were performed blind to the economics of the proposals. This was done to make the Technical Evaluation as impartial as possible.

Q. Did all of the proposals pass the Minimum Technical Requirements evaluation?

A. The Minimum Technical Requirements evaluation uncovered some issues that needed further clarification from all of the bidders, which they attempted to provide, although the clarifications did not resolve all the issues identified. Because DEF had a limited number of bidder proposals to evaluate, DEF elected not to disqualify any proposal from further evaluation, and to consider the remaining issues, as necessary, in any final evaluation of the proposals. If the further economic analysis in the RFP evaluation process eliminated the proposals with these issues from further consideration, there was no need to resolve these issues. If not, then, DEF could also seek to resolve them later in the evaluation process through negotiations with the bidders.

Q. Was this approach also acceptable to the independent monitor and evaluator?

A. Yes. Mr. Taylor participated in this evaluation and the communications with the bidders for further clarifications of their proposals and information in connection with the Minimum Technical Requirements evaluation. Mr. Taylor was aware of the issues that arose during this evaluation and the lack of complete clarity regarding the unresolved issues after the additional information or clarification was provided by the bidders. He agreed, however, with the Company's approach to table these issues until DEF had completed further analysis of the bid proposals.

Q. Were you then ready to announce your Short List?

A. No, as I explained above, DEF needed further clarification of some of the information provided by the bidders or additional information with respect to certain issues that were not resolved in the proposals and by prior clarifications or information from the bidders. DEF realized, however, that there were only twelve alternative proposals. Although there still were non-conformance issues or risks associated with the 2018 RFP Threshold Requirements or Minimum Technical Requirements that the RFP evaluation teams had identified, because there were a limited number of bid proposals, DEF decided to consider all bid proposals in the further economic analysis in the 2018 RFP evaluation process. As a result, there was no Short List. DEF simply elected to continue its evaluation of all bid proposals subject to all the requirements of the 2018 RFP.

Q. Did you notify the bidders of this decision?

A. Yes. All bidders were contacted by DEF in writing on March 3, 2014 for further clarification or information about their bid proposals to assist DEF in its evaluation. In that same letter, DEF informed the bidders that, because of the limited number of proposals DEF received in response to the 2018 RFP, DEF was continuing to evaluate all proposals utilizing all steps of the RFP process as may be necessary in its evaluation of their proposals.

D. INITIAL DETAILED EVALUATION.

Q. What was the next step in your evaluation of the bid proposals in response to the 2018 RFP?

A. DEF proceeded with its Initial Detailed Evaluation. In this step, the bid proposals were compared to the Citrus County Combined Cycle Power Plant NPGU. In order to prepare for detailed production cost modeling DEF created a set of portfolios in which proposals were combined with each other and/or with the generic units to provide adequate resources to meet the 2018 need. These portfolios were then analyzed to determine the CPVRR of that resource plan.

The analyses were performed for a study period of thirty-five years to capture all of the costs associated with each bidder proposal resource plan. DEF chose thirty-five years for the study period in the evaluation because this period coincided with the service life of the Citrus County Combined Cycle Power Plant NPGU. A resource plan incorporating a bidder proposal had to extend for 35 years to replace the Company's base generation resource plan including the Citrus County Combined Cycle Power Plant NPGU. The generation supply alternatives that could be selected were generic combustion turbine and combined cycle units.

Q. You mentioned the combination of bid proposals in resource plans. Why were combinations of bid proposals used to develop resource plans in your optimization analyses?

A. As I testified earlier, none of the bidder's proposals to the 2018 RFP satisfied the Company's reliability need for 1,640 MW of generation in 2018. In fact, the collective generation supply capacity of all bidder proposals did not meet the Company's 1,640 MW need. The total generation capacity offered by all bidders in response to the 2018 RFP was 1,328 MW. Additionally, most of the bidders proposed generation terms that did not equal the 35-year expected service life of the Citrus County Combined Cycle Power Plant NPGU and the few that did were not realistic terms for the proposed generation. As a result, DEF could have rejected all the bids without any evaluation because they failed individually and collectively to meet DEF's reliability need in the 2018 RFP.

DEF, nevertheless, decided to evaluate the bidders proposals to see if there was some combination of them, either individually or collectively, with generic resources to meet DEF's reliability need that was superior to the Citrus County Combined Cycle Power Plant NPGU. We, therefore, looked for reasonable resource combination scenarios to evaluate as resource plans for the bidder proposals. These scenarios included a range of resource plan scenarios that included all bidder proposals and generic combustion turbines to scenarios with less than all or single bidder proposals and either generic combustion turbines or combined cycle units. In all these bidder proposal resource plan scenarios some combination of generic combustion turbines or combined cycle units were needed both to meet the reliability need commencing in 2018 and to "backfill" the bidder proposed generation when it went off line before the end of the expected service life of the Citrus County Combined Cycle Power Plant NPGU. Exhibit No. ___ (BMHB-12) includes a description of the bidder proposal resource scenarios that were evaluated in the Company's Initial Detailed Evaluation.

Q. Please explain the optimization analyses you performed for the Initial Detailed Evaluation of the 2018 RFP bidder proposals.

A. While the economic screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the detailed analyses assessed the impact of each proposal resource plan on total system costs and compared those costs to the costs of a Base Case optimal resource plan. The impact on total system costs is important because it shows the net impact on the customer of choosing an alternative, including both the project cost and the impact the alternative would have on system operating costs, for example, fuel and the variable O&M of the other units on DEF's system. DEF created tables of fixed costs including capacity payments, capital requirements for generation and transmission, fixed O&M and fixed gas transportation rates based on the information provided by the bidders, transmission and fuels evaluations, and generic unit information. This data was combined with the results of detailed production cost runs using EPM to establish a total CPVRR for each portfolio.

Q. What was in the Base Case optimal resource plan?

A. The Base Case was the Company's optimal resource plan, which included the Citrus County Combined Cycle Power Plant NPGU. As I testified above, the Citrus County Combined Cycle Power Plant was identified in the Company's IRP process as the NPGU or the optimal self-build generation that met DEF's reliability need in 2018. The 2018 RFP evaluation process determined if there was any alternative among the bidder proposals that provided a lower overall CPVRR, while meeting DEF's technical and reliability criteria, than the Citrus County Combined Cycle Power Plant NPGU. To this end, all the bidder proposal resource plan alternative scenarios were compared to the NPGU in the Company's Base Case.

Q. **Where do you get the assumptions for generic unit costs and operating characteristics?**

A. DEF engages in an annual process of updating projected costs for generic units. DEF hires an industry recognized power plant engineering and construction firm, in this case, Burns and McDonnell, to produce costs for the construction and operation of an array of generation technologies and configurations. DEF subject matter experts then review the data and may make adjustments to reflect specific areas of knowledge including benchmarking against recent projects and operating cost data from the Duke Energy fleet. This data includes both conventional generation and renewable generation and forms the basis for the technology comparisons shown in Exhibit No. ___ (BMHB-5).

For the screening of alternatives, the data are generic in nature and thus not site specific. The costs and operation parameters are adjusted to reflect installation in the southeastern United States. The operating characteristics are based on state-of-the-art designs, and for most technologies, the performance and costs are based on a specific size unit.

Q. How does the generic data compare to the costs for the Citrus County Combined Cycle Power Plant?

A. The generic data are reasonable estimates of the cost and performance characteristics of the technologies based on the best available, generic, utility-industry cost information. DEF uses this generic data for the cost and performance characteristics of the combustion turbine and combined cycle generation technologies in its IRP process each year, including the preparation of the Company's 2013 and 2014 TYSPs. The generic data for these generation technologies are planning estimates, however, and they are not meant to be "budget quality" estimates for the actual construction of plants containing these generation technologies. In general, they are conservative estimates. In other words, the generic unit costs are higher, and the performance of the generic unit is less efficient, than the costs and performance characteristics based on actual construction contract costs for a specific site and manufacturer costs and specifications for a specific plant.

Q. Did you make any adjustments to the generic unit data in the 2018 RFP evaluation?

A. Yes. We made two adjustments to the generic unit performance characteristics. First, we assumed that the generic combined cycle power plants that were added to the bidder resource plans to meet the 1,640 MW reliability need in 2018 were equally as efficient as the technology for the Citrus County Combined Cycle Power Plant NPGU planned for 2018. As a result, we assigned the same performance characteristics and operation costs to these generic combined cycle power plant units that are in the 2018

RFP for the Citrus County Combined Cycle Power Plant NPGU. Second, we assumed that the future generic combined cycle power plants that must be added to the bidder resource plans as "backfill" units because the bidder proposed generation does not extend for the life of the Citrus County Combined Cycle Power Plant NPGU were marginally more efficient units because of technological advances. In other words, we assumed that the technological advances in the combined cycle technology that we have seen in the past ten years would continue for future combined cycle units. This assumption led to better performance characteristics and lower operating costs for the future generic combined cycle power plants than the Citrus County Combined Cycle Power Plant NPGU. Both of these adjustments favored the bidder proposal resource plans.

Q. Please explain what production cost models DEF used and what they do.

A. DEF uses two different costing models in combination along with spreadsheet calculations of certain cost elements to determine total production cost and CPVRR values for various resource alternatives. Our two primary modeling tools are Strategist and EPM. As I explained above, Strategist is a utility system, resource optimization model. We use Strategist to develop optimal resource plans where the objective is to minimize the CPVRR for the DEF generation system, subject to the 20 percent Reserve Margin constraint. In the case of the analysis for the RFP, Strategist was used to develop resource plan alternatives for evaluation to develop the Base Optimal Expansion Plan which included the NPGU and was presented in the 2014 TYSP and used as the basis for the RFP resource plans.

Inputs to the Strategist model include the load and energy forecast and the costs and characteristics, such as heat rates, outage rates, and maintenance requirements, of the existing DEF generating units and DEF 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. With these descriptions of the demand and existing and future resources, Strategist develops 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 plan from lowest to highest cost.

DEF reviews the lowest cost alternatives for feasibility and then uses these plans along with production performance and cost data as inputs to EPM. 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. Production cost results from EPM were combined with fixed cost calculations from Strategist to confirm the selection of the Base Case Expansion Plan reflected in the 2014 TYSP.

Q. Please explain how the resource plans were identified for the evaluation of bids in the RFP.

A. As discussed previously, because the bids individually and collectively did not meet DEF's 2018 resource need, DEF created portfolios of resources as alternatives to meet the 2018 need. For evaluation purposes DEF used the resource plan identified in the base optimum plan, but removed the NPGU from the portfolios for evaluation of the proposals. DEF then constructed groups of resources using the proposal received and generic units in combination to meet the 2018 need. All the new resources, proposed or generic, were assumed to come in service in 2018. All later resources in the plan, e.g., the 2021 undesignated combined cycle, were kept the same in all resource plans for evaluation. This allowed for an "apples to apples" comparison in which variation in resources later in the plan would not distort the effects of 2018 selections. The only exception to this was the use of the backfill units which were inserted into the plan at the end of the term of each proposal to provide adequate capacity to complete the 35 year evaluation. The portfolios created for evaluation are shown in Exhibit No. ___ (BMHB-12).

Q. How were the models then utilized in the evaluation of bids in the RFP?

A. For each of the proposals, generic units, and backfill units, tables were constructed calculating the fixed costs including capital revenue requirements, fixed O&M, transmission charges, and fixed gas transportation charges. Then, operating data was input to EPM for each resource plan. EPM was used to calculate production cost results for each of the portfolios. The production cost results were then combined with the fixed cost information to get a total CPVRR for each portfolio.

Q. Were any other costs or criteria considered with the optimization analyses in the Initial Detailed Evaluation?

A. Yes. DEF conducted transmission reviews and further technical criteria evaluations. The transmission reviews were screening type studies to provide reasonable estimates of the transmission impacts to integrate the bidder proposals into the DEF system. The technical criteria evaluation was a more detailed assessment of the non-price attributes of the Minimum Technical Requirements that I previously described in my testimony.

Q. Please describe the evaluation of the transmission impacts in the Company's transmission reviews in its Initial Detailed Evaluation.

A. Because no bidder individually or collectively met the Company's 2018 reliability need identified in the 2018 RFP, the resource plan scenarios that reasonably combined individual or combinations of individual bidder proposals with generic units to meet the Company's capacity need were used to form transmission groups for the DEF transmission system in the transmission review studies. The transmission groups were identical to the generation portfolios evaluated. These transmission groups were studied for their overall impact to DEF's system and the Bulk Electric System ("BES").

These transmission service studies were performed consistent with North American Electric Reliability Corporation ("NERC"), FRCC, and DEF standards to ensure that DEF can serve its customers and meet transmission service obligations commencing in and extending beyond 2018. Contingency screening tests were performed at summer and winter peak load conditions, and with various DEF generators and facilities available and economically dispatched, to determine and potentially mitigate reliability criteria violations. Any reliability criteria violations identified on DEF's system in the tests were resolved by acceptable remedial action, including when appropriate, transmission facility upgrades or new transmission facilities. Only those transmission facility upgrades or new facilities necessary to physically transfer the proposed power from the DEF system receipt point to the load center consistent with reliability standards for the conditions commencing in the summer of 2018 were identified in the studies.

Once a list of transmission facility upgrades or new transmission facilities was identified from the studies, the next step in the transmission review was developing cost estimates for the upgrades and new facilities and estimated schedules to complete the transmission upgrades or new facilities. Cost and schedule estimates for the necessary transmission facility upgrades or new transmission facilities were based on DEF and industry standard cost estimations and DEF's experience. DEF relies on the same transmission cost and schedule estimates in its own IRP and transmission planning processes.

Bidders were required to provide as part of their 2018 RFP response package detailed information regarding their proposed power plants to enable DEF to perform the transmission reviews in the transmission group service studies. DEF used the information provided by the bidders in response to the 2018 RFP and in response to DEF requests for more information or clarification in performing its transmission review studies. These transmission group service studies and the results of these studies are discussed in more detail in the testimony of Mr. Ed Scott in this proceeding.

Q. Did any of the bidder proposals require changes to the DEF transmission system?

A. Yes. All of the bidder proposal resource scenarios required transmission facility upgrades or new facilities on DEF's system, the BES, or both. The range of estimated transmission costs for each bidder proposal resource plan scenario is a low of approximately $135 million to a high of approximately $202 million. Again, these results are also explained by Mr. Scott in his direct testimony in this proceeding.

Q. Were the transmission review results included in the Company's Initial Detailed Evaluation?

A. Yes. The addition of the necessary transmission costs for the bidder proposal resource plan scenarios increased the costs of the bidder proposal resource plan scenarios relative to the Citrus County Combined Cycle Power Plant NPGU in every case. The reason for this is that the Citrus County Combined Cycle Power Plant NPGU requires no transmission costs beyond the costs required to connect the Plant with the DEF transmission system and BES. The Citrus County Combined Cycle Power Plant NPGU takes advantage of available Company transmission facilities near the CREC that were built to handle the power generated by the CREC. With the existing and planned retirements of CR1, CR2, and CR3 at the CREC, respectively, these existing transmission facilities are available for additional new generation built in the vicinity of the CREC. There are, therefore, no transmission costs associated with upgrades or new facilities for the DEF transmission system or the BES for the Citrus County Combined Cycle Power Plant NPGU.

None of the bidders to the 2018 RFP proposed generation in the vicinity of the CREC or Citrus County. As a result, none of the generation proposed by the bidders utilizes the available DEF transmission facilities located in this area that were built for CREC generation that has or will be retired by 2018.

Q. Were potential bidders told about the benefits of this location in the 2018 RFP?

A. Yes. DEF explained in the 2018 RFP that the preferred BES location for new DEF capacity was Citrus County. DEF even explained why the Citrus County location was preferred. DEF explained that new generation capacity would replace generation that was being retired in the same area and that there were transmission reliability benefits for DEF and neighboring transmission systems if the new generation capacity was located in that area. DEF further explained that new generation capacity in that area could take advantage of the BES transmission capacity that would become available with the generation capacity retirements in the area. DEF also explained that, if the new generation capacity was not located in the vicinity of Citrus County, DEF expected that significant transmission network upgrades would need to be constructed. Finally, DEF told potential bidders that DEF had located the Citrus County Combined Cycle Power Plant NPGU in Citrus County. Despite this information in the 2018 RFP, none of the bidders submitted proposals for generation capacity in the vicinity of Citrus County.

Q. What did the further technical criteria review involve in the Initial Detailed Evaluation?

A. DEF performed a more detailed qualitative assessment of the operational quality, development and commercial feasibility, and project value technical criteria. This was a more in depth analysis of the information about these criteria provided by the bidders in the 2018 RFP bidder response packages in response to DEF's stated preferences for these criteria in the 2018 RFP solicitation document. The closer the bidders' information was to DEF's preferences for each of these technical criteria the more valuable the bidder proposal to DEF on a qualitative basis.

Q. What were the results of the further technical criteria evaluation?

A. The final technical criteria evaluation of the proposals revealed continuing Threshold Requirement and technical criteria issues. Again, however, given the limited number of bidder proposals in response to the 2018 RFP, we continued to consider these issues as a qualitative risk associated with the proposals in our evaluation.

Our view of the further technical criteria evaluation was influenced by the fact that all of the bidder proposals required generic units to fulfill the reliability need for the Company. As a result, the technical criteria review of a resource plan including some or all of the bidder proposals involved the assessment of unplanned and undeveloped generic units that the Company was not sure the Company could even plan and build in time to meet its reliability need. None of these issues existed with the self-assessment of the Citrus County Combined Cycle Power Plant, which of course, did meet the Company's reliability need and could be built to meet that need.

Consequently, the Citrus County Combined Cycle Power Plant clearly ranked ahead of all the bidder proposals resource scenario alternatives for all the technical criteria. The determinative factor was the need to site, license, obtain environmental permits, engineer, design, and construct the unplanned and undeveloped generic units in the bidder proposal resource scenarios.

Q. What were the results of the Initial Detailed Evaluation?

A. Exhibit No. ___ (BMHB-13) shows the economic results of the optimization analyses in the initial detailed evaluation step in the 2018 RFP evaluation process. The exhibit shows the difference in total system CPVRR associated with each alternative resource plan scenario compared to the Base Case. The analysis shows that resource plan scenario 8 had the lowest future cost for DEF customers of any of the resource plan scenarios including the proposals we received from bidders in response to the 2018 RFP. Scenario 8 was still over $375 million less cost-effective than the resource plan that included the Citrus County Combined Cycle Power Plant NPGU.

Q. Were any further analyses performed by the Company?

A. Yes. Following the Initial Detailed Evaluation the Company also performed the more detailed evaluation in the Final Detailed Evaluation to compare the bidder proposal resource scenarios to DEF's self-build alternative, the Citrus County Combined Cycle Power Plant NPGU. The Final Detailed Evaluation involved a more detailed economic analysis, which included more refined financial analyses, which included the cost of imputed debt by determining the additional equity cost related to potential purchased power arrangements for the bidder proposals.

The results of the production costing analyses were incorporated into the financial analysis of each alternative bidder proposal resource scenario. In addition to the production costs associated with each alternative, that is, the energy charges of each proposal and the Citrus County Combined Cycle Power Plant operating costs, the change in system production costs as a result of each alternative bidder proposal resource scenario, relative to the base case, was also a part of the financial analysis.

The fixed costs of the alternatives, that is, the fixed charges of the bidder proposals and the fixed costs of the generic units in the resource scenarios, and the Citrus County Combined Cycle Power Plant construction costs and fixed O&M costs, were captured in the financial analysis. As mentioned before, each bidder proposal alternative resource scenario was compared to a Base Case that included the Citrus County Combined Cycle Power Plant NPGU.

The transmission construction costs to integrate each of the bidder proposals and the Citrus County Combined Cycle Power Plant into the DEF transmission system were included in the detailed economic analysis. The annual cash flow pattern of the construction costs was based on expenditure patterns typically experienced for transmission lines, transformers, and other necessary transmission facilities. Finally, we also included the cost of imputed debt by determining the additional equity cost related to the purchased power proposal.

Q. Why did you include the cost of imputed debt in your analysis?

A. The cost of imputed debt was applied to proposals to assure that the total costs of proposals include the marginal impact of the fixed future power purchase agreement payment commitments on DEF's capital structure. This additional cost is the direct result of incurring fixed, long-term future payment obligations in the power purchase agreements. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments associated with these fixed, long-term payments. Also, Rule 25-22.081(1)(g) F.A.C. requires a utility to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a nonutility generator be executed. The cost of imputed debt quantifies that potential. The cost of imputed debt, however, was not the determinative factor in the quantitative evaluation of the most cost-effective option to meet the Company's 2018 reliability need. The Citrus County Combined Cycle Power Plant was the most cost-effective option to meet the Company's reliability need whether or not the cost of imputed debt was considered in the evaluation.

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

A. In CPVRR terms, the Citrus County Combined Cycle Power Plant was found to be approximately $477 million less expensive than the least cost alternative bidder proposal. Exhibit No. ___ (BMHB-14) shows the results of the analysis. This depicts the difference in the total CPVRR associated with each alternative compared to the base case. The results of the detailed financial analysis of the proposals and the

Citrus County Combined Cycle Power Plant demonstrate that the Citrus County Combined Cycle Power Plant is clearly the most cost-effective alternative for supplying generation to meet the needs of the DEF's customers.

Q. Why is the Citrus County Combined Cycle Power Plant less expensive than the other alternatives?

A. The Citrus County Combined Cycle Power Plant is a state-of-the-art, highly efficient, natural-gas fired plant located on a site that takes advantage of adjacent site infrastructure and existing transmission infrastructure providing available transmission capacity for delivery of the Plant's power to DEF's customers. All but one of the bidder proposals involved existing, older and, thus, less efficient natural-gas fired combined cycle units and all of the bidder proposals, including the one new combined cycle generation units, were located at sites that did not take advantage of the available transmission capacity. These are the primary reasons why the Citrus County Combined Cycle Power Plant proved to be more cost effective than any of the bidder proposal resource scenarios, even if the bidder proposals had met DEF's reliability need, which they did not do.

All bidder proposals failed to meet the 1,640 MW reliability need in 2018 and all of them failed to meet that need for the duration of the expected 35-year life of the Citrus County Combined Cycle Power Plant NPGU. This required DEF to add generic units to the bidder proposals to create a resource plan scenario to meet DEF's reliability need. For reasons I described above, the characteristics of these generic combined cycle units were beneficial to the bidders in the resource plan scenarios created around their proposals to meet the Company's reliability need. In the final detailed economic analysis, the more these generic units were used in the resource plan scenarios to meet DEF's reliability need, the more cost effective the plans were, and conversely, the more the bidder proposed units were used in the resource plan scenarios the less cost effective they were.

To illustrate this result, the highest CPVRR and thus the least cost effective bidder proposal resource plan scenario was the one that included all bidder proposed units plus generic units to meet the reliability need. The next least cost effective bidder resource plan was the one that included the three largest bidder units in the resource plan scenario. See Exhibit No. ___ (BMHB-14) to my direct testimony. In sum, the more the bidder proposed units were used in the resource plan the worse the plan was to meet DEF's reliability need.

Q. Did DEF perform any sensitivity analyses?

A. Yes, we performed two sensitivity analyses. One sensitivity analysis was a high natural gas price case and the other was a zero carbon price case. DEF used its high natural gas forecast for the high natural gas price case. The zero carbon price case was an alternative to the Base Case, which included an estimated carbon cost impact based on the Duke Energy forecast. The Duke Energy base carbon cost forecast is within the range of carbon cost forecasts previously used by the Company in its IRP process.

Q. What were the results of the high natural gas price case sensitivity analysis?

A. Exhibit No. ___ (BMHB-14) to my direct testimony also contains the results of the Company's high natural gas price case sensitivity analysis. As shown in Exhibit No. ___ (BMHB-14), the Citrus County Combined Cycle Power Plant NPGU is still the most cost-effective resource for DEF's customers. The next lowest-cost resource scenario including a bidder proposal was $464 million more costly for DEF's customers than the Citrus County Combined Cycle Power Plant NPGU. This is a slightly better CPVRR result for the least cost bidder proposal resource plan scenario than the reference case bidder proposal resource plan scenario, but the result is still less cost effective than the Citrus County Combined Cycle Power Plant NPGU. One significant reason the CPVRR result in this scenario improves slightly is because of the enhanced efficiency of the generic combined cycle plant that follows the bidder proposed unit in the resource plan scenario to meet DEF's reliability need. A second factor is that, with higher gas prices, additional coal generation displaces lower efficiency gas, in some cases from the bidder proposals. The bidder proposed unit does not contribute to the improved cost effectiveness in the high natural gas price case.

Q. What were the results of the zero carbon price case sensitivity analysis?

A. Exhibit No. ___ (BMHB-14) to my direct testimony also contains the results of the Company's zero carbon price case sensitivity analysis. Again, as shown in Exhibit No. ___ (BMHB-14), the Citrus County Combined Cycle Power Plant NPGU still is the most cost-effective resource for DEF's customers. The next lowest-cost resource scenario including a bidder proposal was almost $270 million more costly for DEF's customers than the Citrus County Combined Cycle Power Plant NPGU. Also, again, the reason the CPVRR result in this scenario improves is not because of the bidder proposed unit. The CPVRR results improve in the no carbon price case because of the interplay of the increased dispatch of the existing DEF coal units and the more efficient combined cycle natural-gas fired plant that follows the bidder proposed unit in the resource plan scenario to meet DEF's reliability need. The bidder proposed unit does not contribute to the improved cost effectiveness of the bidder proposal resource plan scenario in the zero carbon price case.

Q. Did you perform any other sensitivity analyses?

A. No, we saw no need to perform any further sensitivity analyses beyond the high natural gas price case and no carbon cost case sensitivity analyses. A low natural gas price case or a higher or several high carbon cost price cases made little sense when all bidder proposed units but one small renewable unit and the Citrus County Combined Cycle Power Plant were natural gas-fired power plants. As a result, all the resource plan comparisons in the detailed economic analysis were gas-on-gas comparisons. The sensitivities that DEF performed, therefore, adequately explained the relationship between the bidder proposed unit resource plan scenarios and the Base Case including the Citrus County Combined Cycle Power Plant NPGU when natural gas and carbon cost prices were changed in the production cost model resource plan scenarios. Further changes in the natural gas price or carbon cost prices were unnecessary for DEF to understand that the Citrus County Combined Cycle

Power Plant remained the most cost-effective resource option for DEF to meet its reliability need.

In fact, the changes in the CPVRR results in the sensitivities that DEF did perform had more to do with the impact of the generic units in the bidder proposed resource plan scenarios than the bidder proposed units in those scenarios. As I explained above, the bidder proposed units had to be combined with generic gas plants in their resource plan scenarios to meet DEF's reliability need. As I also explained above, DEF also assumed these generic units were equally to slightly more efficient in operation as the Citrus County Combined Cycle Power Plant. As a result, changes in the natural gas or carbon cost prices in the detailed economic analyses caused greater changes in the dispatch of these generic units than the bidder proposed unit relative to changes in the dispatch of other units on DEF's system in the Base Case. What DEF was really measuring in CPVRR terms, then, with changes in the natural gas price or carbon cost price was the cost effectiveness of the generic units in the resource plan scenarios that included the bidder proposed units compared to the Base Case with the Citrus County Combined Cycle Power Plant.

Q. Did this complete your economic analysis of the proposals?

A. Yes, it did.

Q. What was the final step in the DEF 2018 RFP process?

A. The final step in the RFP evaluation process was to select the Final List. However, as discussed previously and as stated in the 2018 RFP, in the event the Citrus County

Combined Cycle Power Plant was found to be clearly superior to the other alternatives, a Final List would not be selected. Based on the results of the 2018 RFP evaluation process, the Citrus County Combined Cycle Power Plant was found to be clearly superior to the other alternatives. As a result, DEF announced on May 13, 2014 that the Citrus County Combined Cycle Power Plant was the most cost-effective alternative to serve DEF's customer reliability needs. This announcement concluded the 2018 RFP evaluation process.

VIII. MOST COST-EFFECTIVE ALTERNATIVE.

Q. Is the Citrus County Combined Cycle Power Plant the Company's most cost-effective alternative for meeting its 2018 reliability need?

A. Yes, it is. As I have described, the Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Citrus County Combined Cycle Power Plant as its next-planned generating alternative. We were able to screen out less cost-effective supply-side alternatives, identifying the Citrus County Combined Cycle Power Plant as the most cost-effective alternative available to us. Further, through our 2018 RFP process, we determined that the Citrus County Combined Cycle Power Plant was also more cost-effective than any of the proposals made to us.

Q. Why is the Citrus County Combined Cycle Power Plant the most cost-effective alternative?

A. The Citrus County Combined Cycle Power Plant is a highly efficient, state-of-the-art natural-gas fired combined cycle generation plant. This high efficiency yields relatively lower production costs than any other option, creating significant relative fuel savings benefits for DEF's customers. The high efficiency coupled with the favorable site location adjacent to the CREC where site infrastructure can be shared and in the vicinity of existing transmission infrastructure capacity adds substantial benefits to this Plant for DEF's customers. No bidder in response to the 2018 RFP proposed a plant that came close to matching the benefits of the Citrus County Combined Cycle Power Plant for DEF's customers. All bidder proposals fell short of the Company's reliability needs, and even when combined with generic, unplanned and undeveloped plants, the closest bidder proposal resource plan scenario was over $470 million less cost effective for DEF's customers. All bidder proposals combined, which still did not equal DEF's reliability need in 2018 and beyond, was over $1.2 billion less cost effective than the Citrus County Combined Cycle Power Plant. Based on DEF's internal, rigorous IRP process, and the competitive market process of the 2018 RFP, the Citrus County Combined Cycle Power Plant is clearly the most cost effective generation resource for DEF's customers.

IX. BENEFIT TO THE STATE.

Q. Is the Citrus County Combined Cycle Power Plant consistent with the needs of Peninsular Florida?

A. Yes, the Citrus County Combined Cycle Power Plant will assist DEF in meeting its 20 percent planned Reserve Margin and it will assist Peninsular Florida in attaining the 15 percent minimum level of planning reserves targeted for the FRCC region. The Citrus County Combined Cycle Power Plant is further located in the vicinity of transmission infrastructure that provides reliability and stability to the Florida electric grid as determined by the FRCC.

X. CONSEQUENCES OF DELAY.

Q. What will be the impact of delay in implementing the Citrus County Combined Cycle Power Plant?

A. If the Citrus County Combined Cycle Power Plant is delayed, DEF will not be able to meet its 20 percent Reserve Margin requirement in 2018. DEF has retired CR3 and currently must retire CR1 and CR2 and will do so by 2018. DEF, therefore, faces a need for reliable generation in 2018. In addition, these retirements lead to grid reliability issues, recognized by the FRCC, in the event the addition of generation in the vicinity of Citrus County is delayed beyond 2018. To avoid reliability issues for the Florida grid, the Citrus County Combined Cycle Power Plant needs to be built and placed in commercial operation in 2018. In addition, delaying the Citrus County Combined Cycle Power Plant beyond 2018, delays the benefits to customers from the most cost effective generation to meet the Company's reliability need in 2018, and exposes customers to higher cost power to meet their energy needs. For all these reasons, DEF needs to move forward with and place the Citrus County Combined Cycle Power Plant in commercial operation in 2018.

XI. CONSERVATION MEASURES.

Q. Did DEF attempt to mitigate its need for the proposed unit by pursuing conservation measures reasonably available to it?

A. Yes, we did. As I discussed above, the Company identified and has implemented a set of cost-effective DSM programs that have successfully met or exceeded Commission-established goals for years. This success has led to diminishing returns on our investment in DSM programs, however, reducing the availability of and results of cost-effective DSM programs. We anticipate that it will increasingly become more difficult to expand our DSM goals and we have adjusted our proposed future year goals accordingly. We fully expect to achieve all of the proposed future year goals, despite the increasing difficulty in achieving them, but achieving these proposed DSM goals does not mitigate the need for the Citrus County Combined Cycle Power Plant in 2018. The Citrus County Combined Cycle Power Plant is needed even if the Company meets all of its proposed DSM program goals.

XII. CONCLUSION.

Q. Please summarize the benefits of the Citrus County Combined Cycle Power Plant.

A. DEF needs the Citrus County Combined Cycle Power Plant to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building the Citrus County Combined Cycle Power Plant, 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 Plant also adds diversity to DEF's fleet of generating assets, in terms of natural gas fuel supply diversity, technology, age, and functionality of the Plant. Having exhausted cost effective conservation measures reasonably available to the Company in the timeframe of the need, DEF selected the Citrus County Combined Cycle Power Plant as its most cost-effective alternative for meeting its reliability needs. The Plant will be a state-of-the-art, fuel efficient, environmentally preferable installation that will be located on a site that takes advantage of existing transmission infrastructure and other infrastructure resources at the CREC adjacent to the Plant site. We are pleased to be able to add this unit to the Company's fleet and we urge the Commission to approve our plan to build the Citrus County Combined Cycle Power Plant.

Q. Does this conclude your testimony?

A. Yes, it does.

Duke Energy Florida, Inc.
Ten-Year Site Plan

April 2014

2014-2023

Submitted to:
Florida Public Service Commission

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

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.

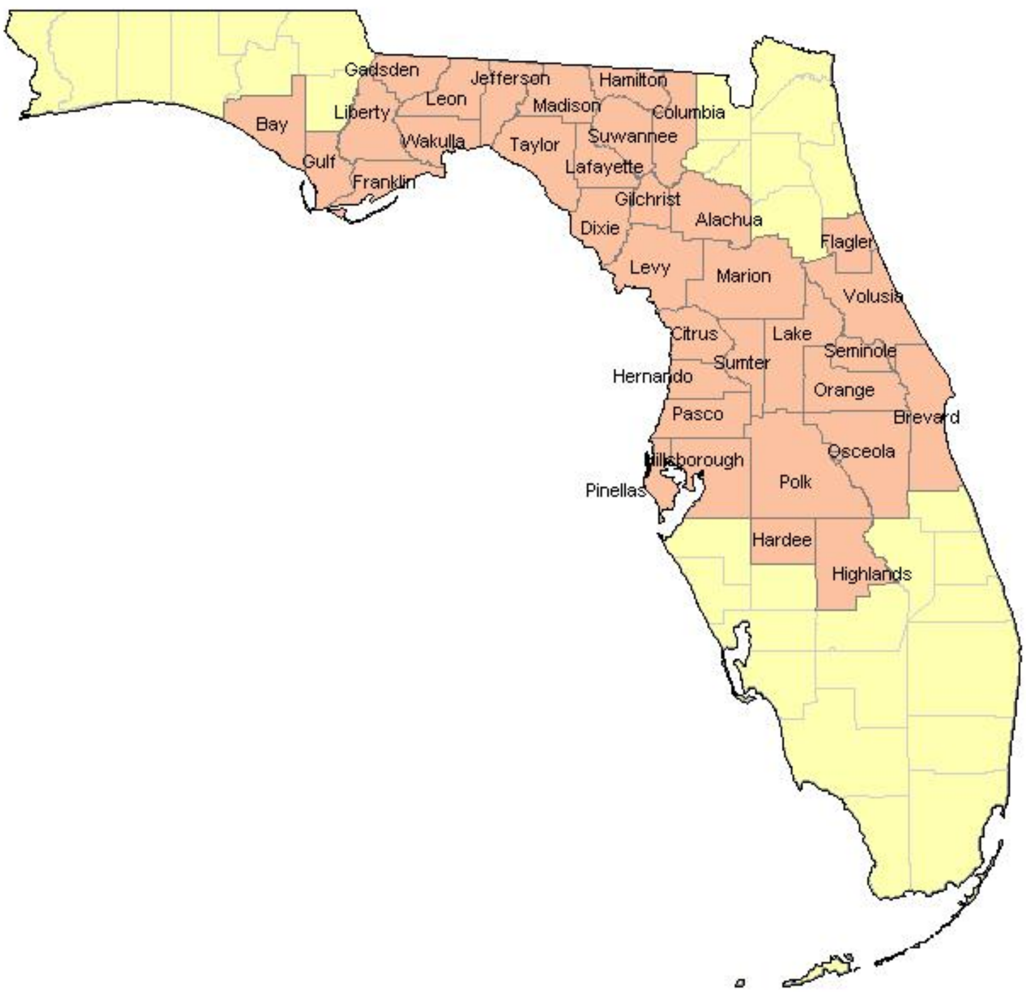
ENERGY MANAGEMENT and ENERGY EFFICIENCY

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

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	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) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) 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.

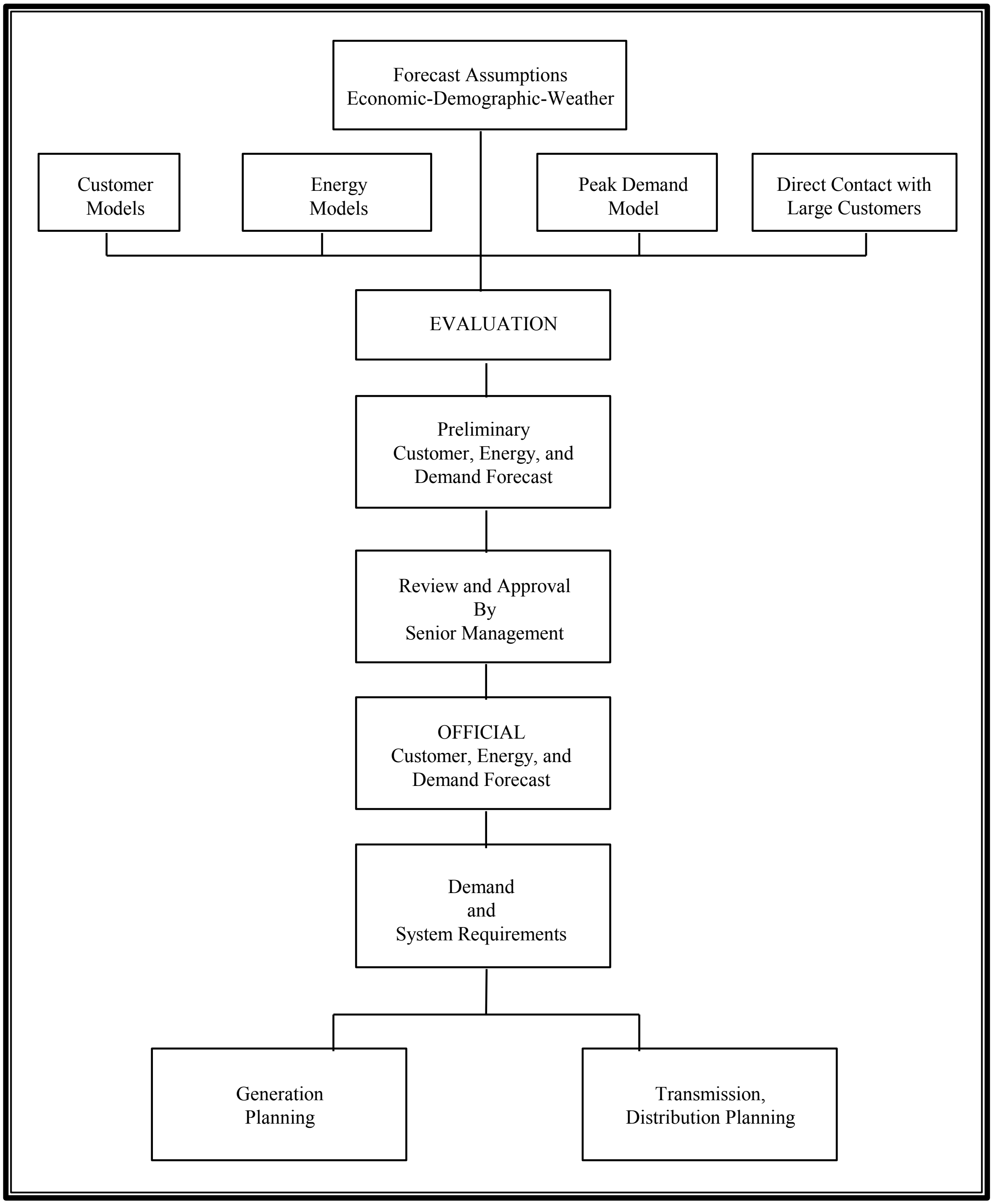
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for 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

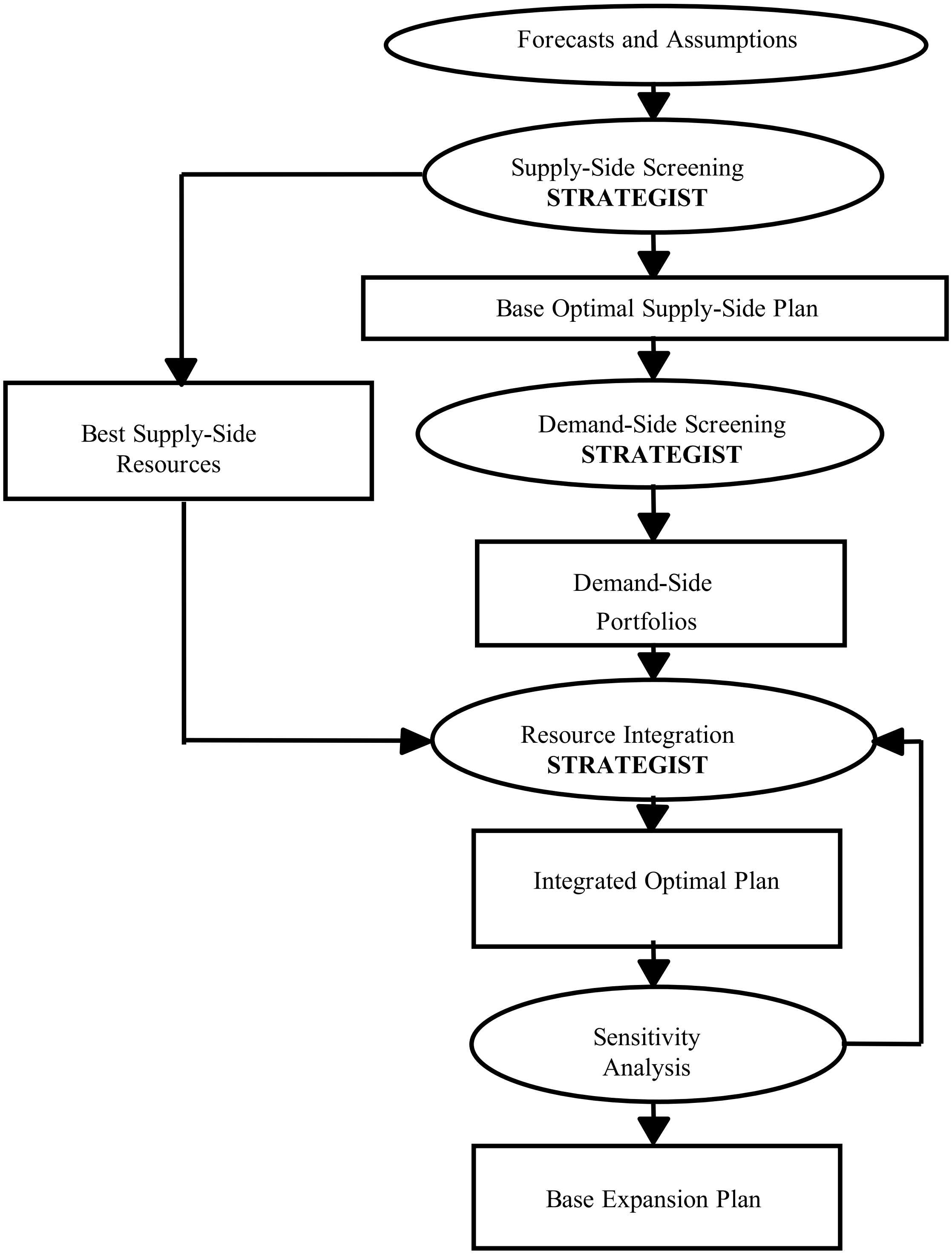
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide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

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.

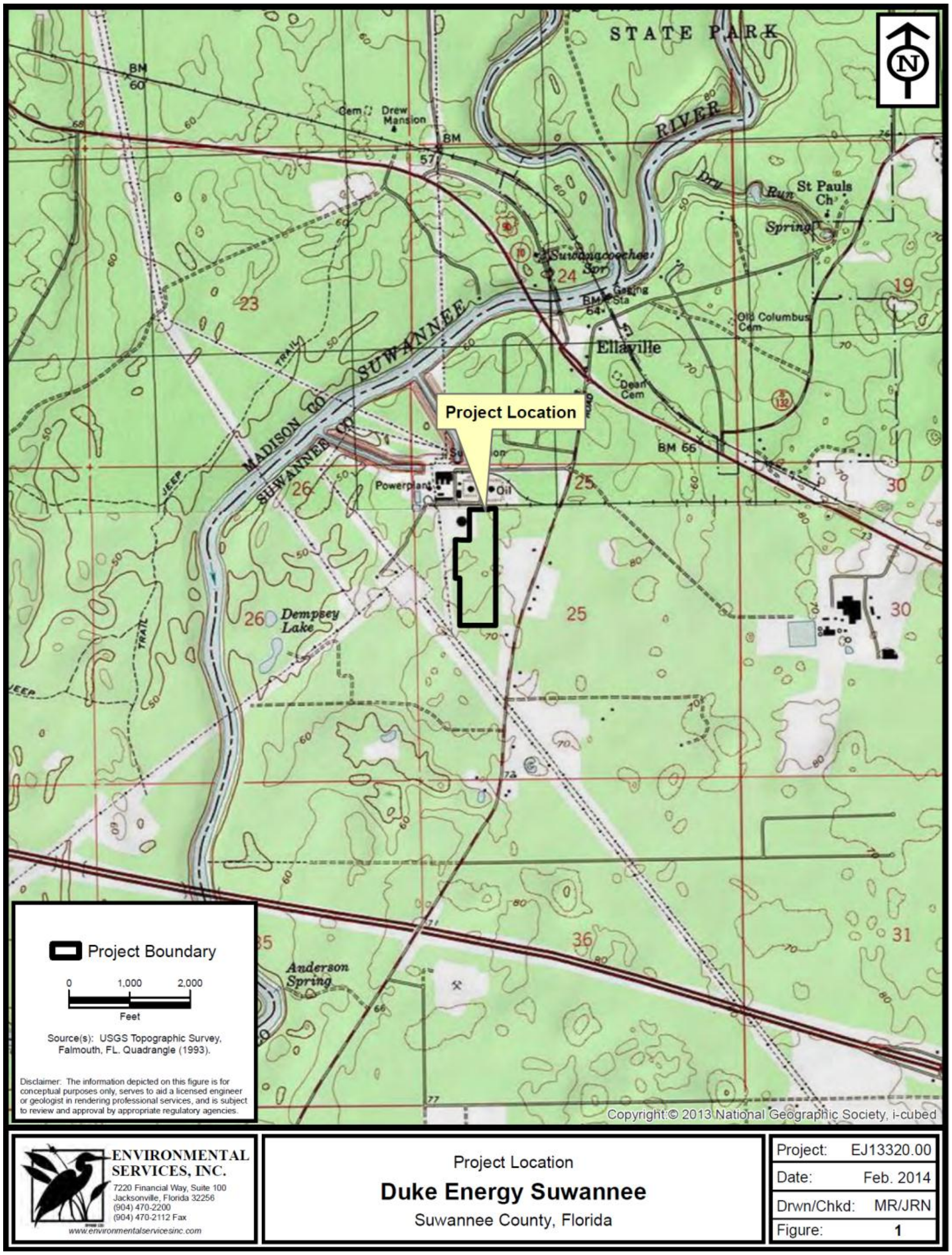
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. 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



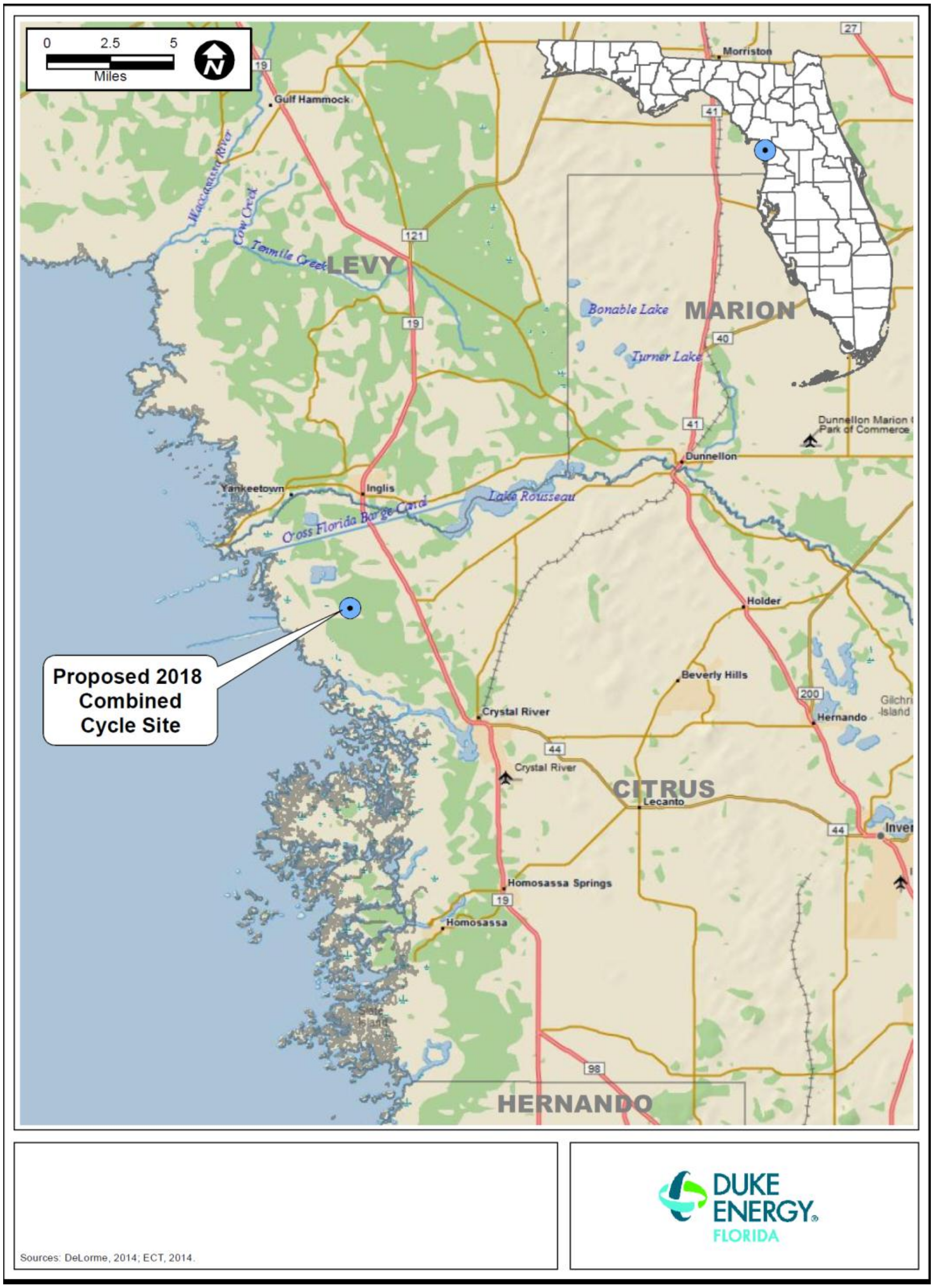
CITRUS COUNTY

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



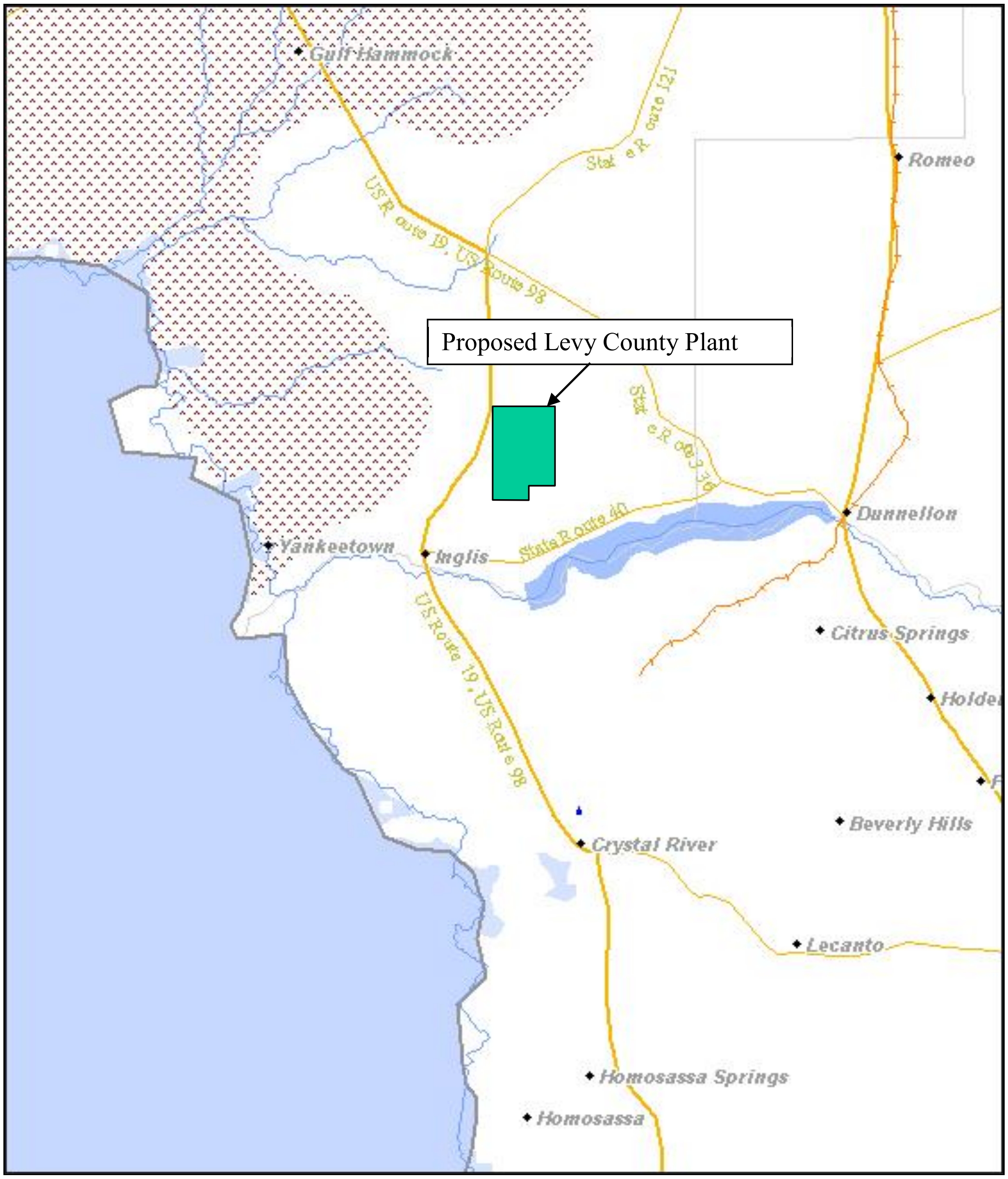
LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

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)

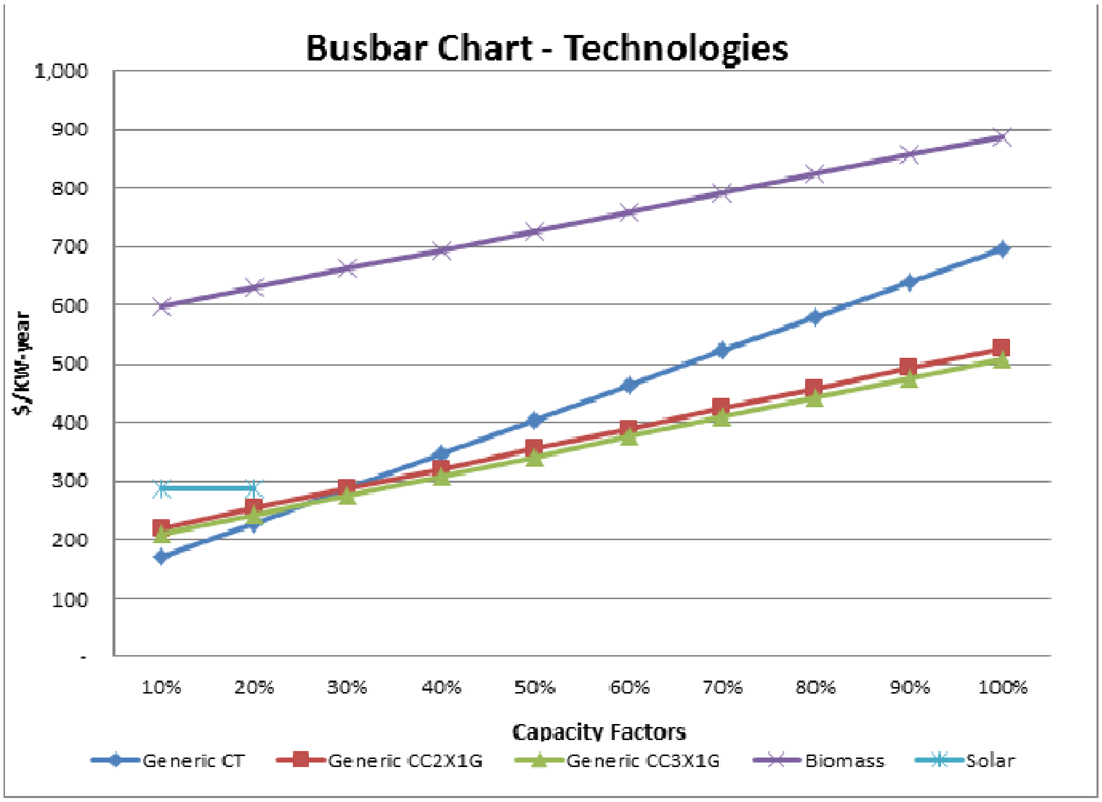


		With Citrus CC		Without Citrus CC	
Year	**Summer Firm Peak Demand**	**Summer Installed Capacity**	**Summer Reserve Margin (%)**	**Summer Installed Capacity**	**Summer Reserve Margin (%)**
2014	8,812	11,024	25.1%	11,024	25.1%
2015	9,042	10,991	21.6%	10,991	21.6%
2016	9,149	11,012	20.4%	11,012	20.4%
2017	9,307	11,232	20.7%	11,232	20.7%
2018	9,439	11,362	20.4%	10,542	11.7%
2019	9,813	12,132	23.6%	10,492	6.9%
2020	9,935	12,027	21.1%	10,387	4.5%

DEF's projected net energy for load growth on DEF's system

	LOAD FORECAST		
	Firm 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
2018	9,544	9,439	41,995
2019	9,639	9,813	43,013
2020	9,971	9,935	43,998
2021	10,059	9,952	44,419
2022	10,144	10,067	44,870
2023	10,225	10,173	45,459

BUSBAR COST COMPARISON



Alternative	Summer	Overnight		Overnight		O&M Costs		Summer	Equivalent	Fuel
	Total	Generation Capital Costs		Transmission Capital Costs		Fixed	Variable	Heat Rate	FOR	Type
	Capacity	2016$		2016$		2016$				
	(MW)	$/Kw	$M	$/Kw	$M	$/Kw	$/Mwh	Btu/Kwh	(%)	
Combustion Turbine	186.66	457	85	142	27	72	10.89	10,343	2.05%	Gas / Oil
Combined Cycle 2x1 G	792.97	904	717	392	311	72	5.72	6,800	6.36%	Gas / Oil
Combined Cycle 3x1 G	1,189.10	870	1,035	349	414	70	4.83	6,820	6.36%	Gas / Oil
Biomass	50.00	4,588	229	124	6	111	5.75	13,000	6.80%	Wood
Solar Photovoltaic	25.00	1,956	49	124	3	89	-	-	-	Solar

* O&M Fixed Costs include Gas Reservation Charges

Docket No. ________
Duke Energy Florida
Exhibit No. ____________ (BMHB-6)
Page 1 of 1

Location of Unconventional Shale Gas Developments and Table of the Current and Expected Gas Production From These Shale Gas Plays

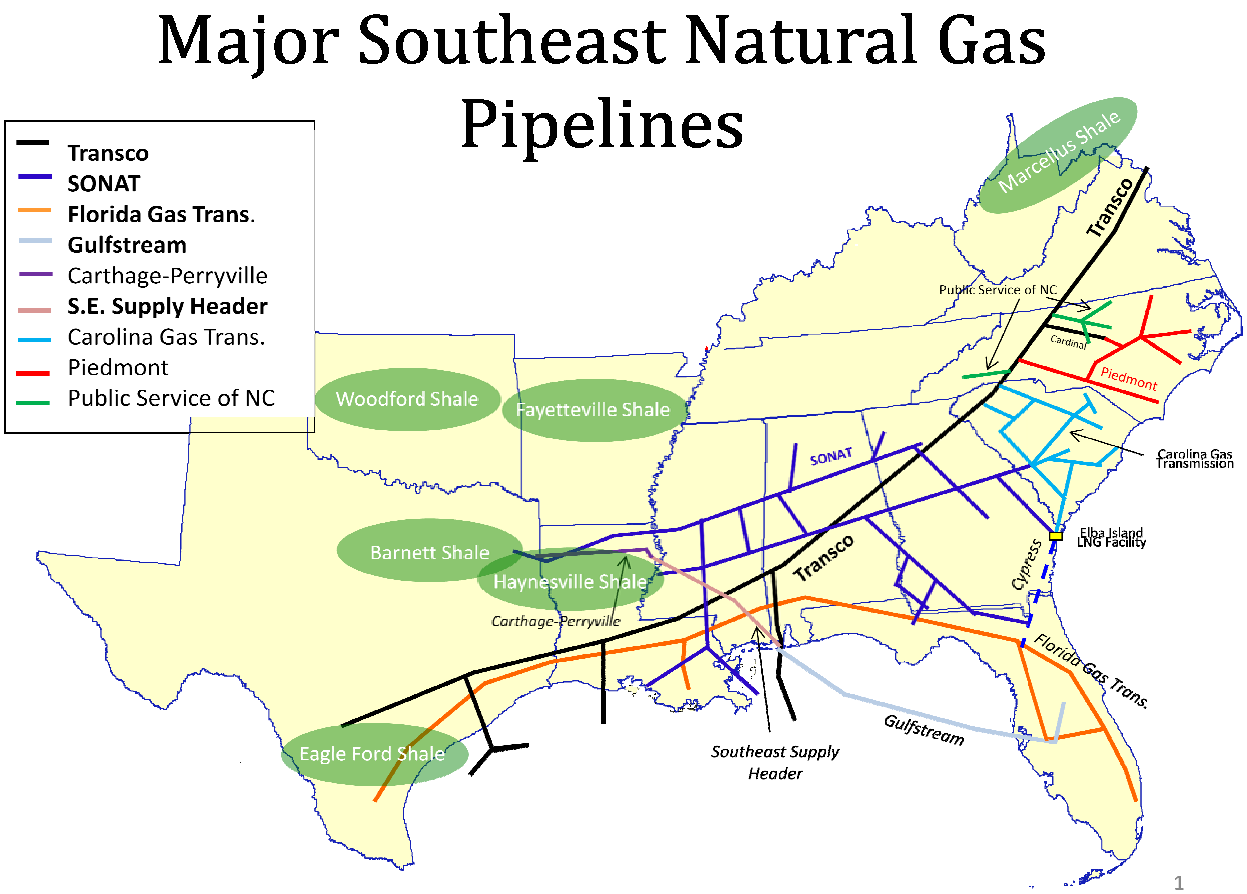
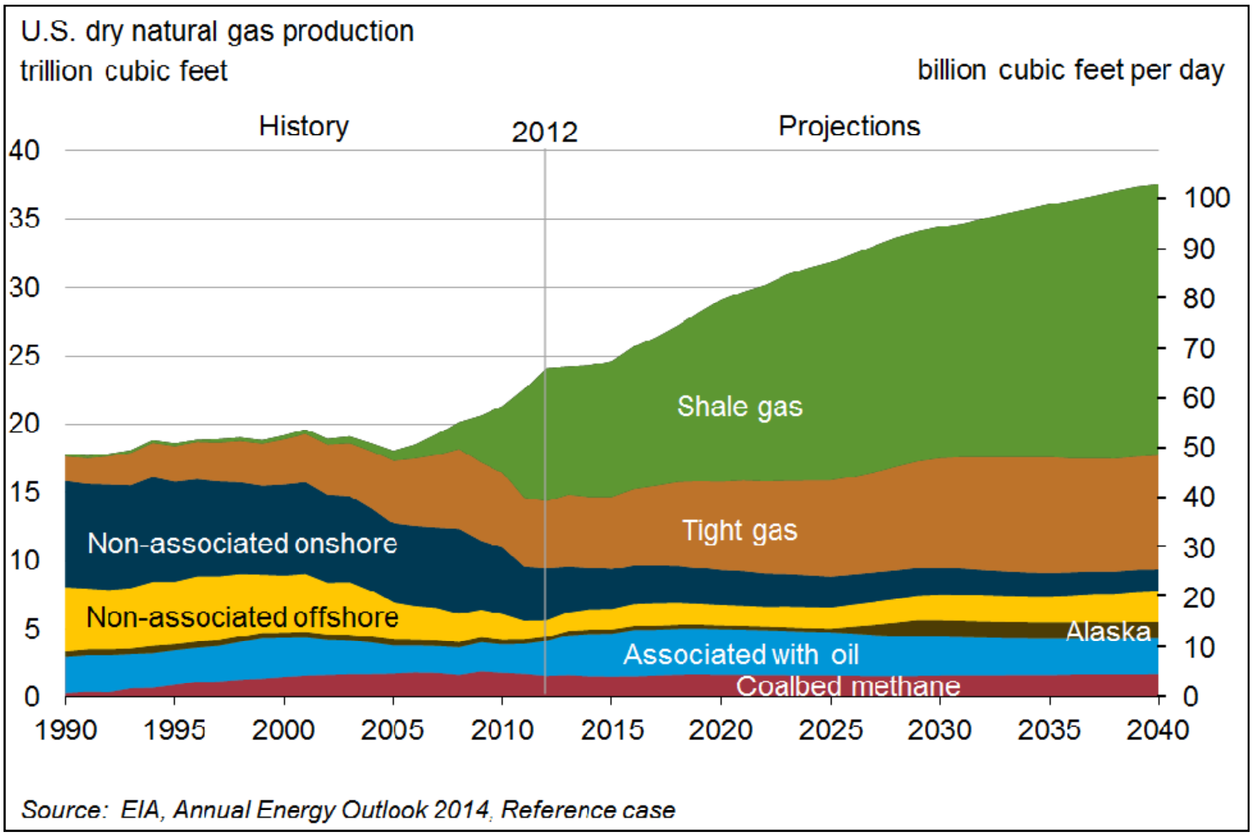
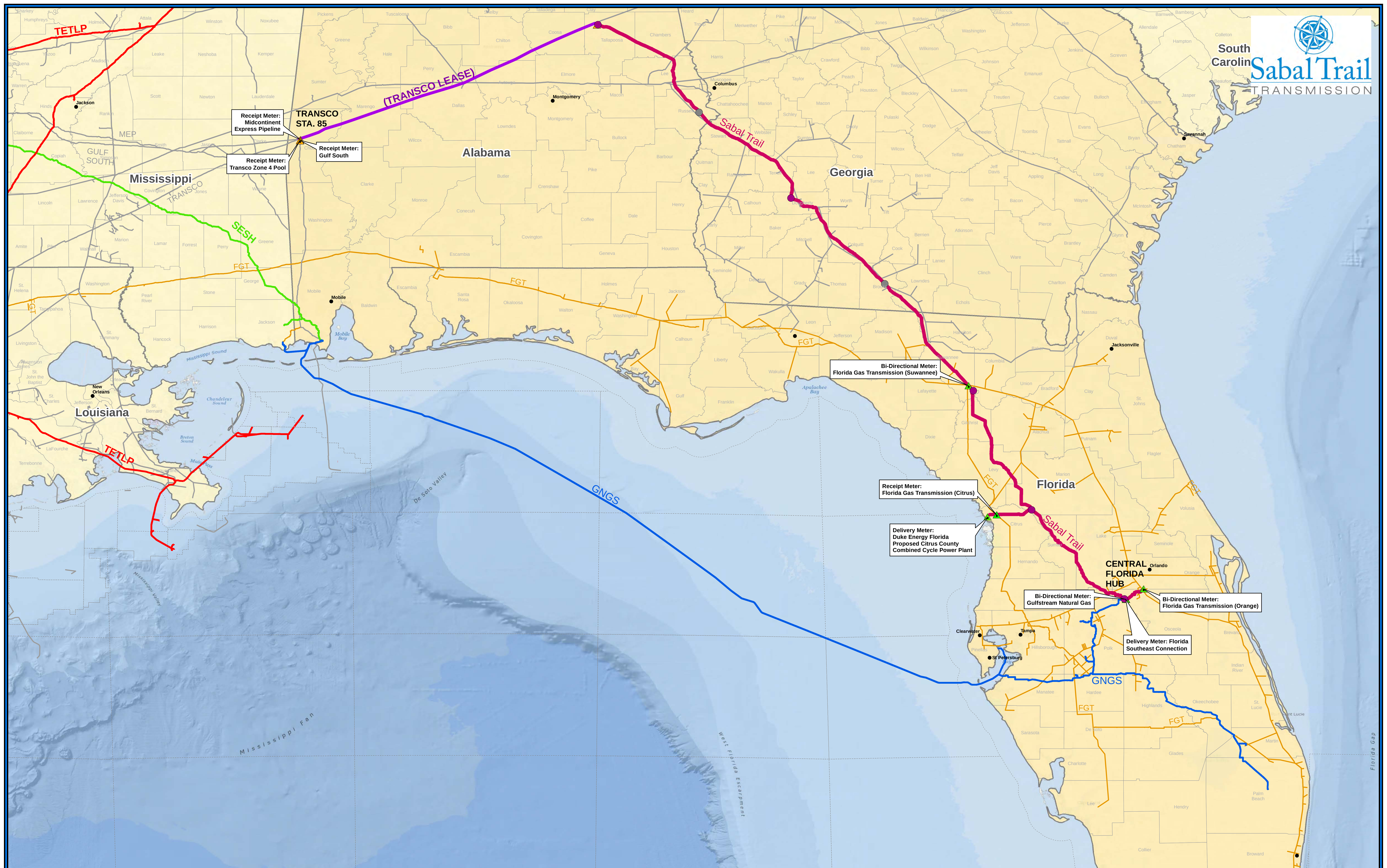


Table of the Current and Future Production from Both Conventional and Unconventional Gas Supply Resources



Sabal Trail Transmission LLC Natural Gas Pipeline



Y:\Personal\Maps\Sabal Trail\Sabal Trail Transmission LLC-Duke Energy - 8-14-13.mxd

2018 RFP Evaluation Process

Step 1
Screening for Threshold Requirements

Step 2
Initial Evaluation

Preliminary Economic Bid Screening
Minimum Technical Requirements

Step 3
Selection of Short List

Step 4
Detailed Evaluation

Initial Detail Evaluation:
Optimization Analysis
Technical Evaluation
DEF Internal Transmission Review

Final Detail Evaluation:
Detail Resource Plan Comparisons
Scenarios
Bidders Clarification & Adjustments if Needed

Step 5
Selection of Final List

Step 6
Contract Negotiations
Contract Development
Transmission OATT Studies:
Transmission Feasibility
Transmission Impact Studies
Transmission Facilities Studies

Step 7
Final Decision

Threshold Requirements

A. General Requirements

- The proposal is received on time.
- The proposal submittal fee is received by DEF.
- The pricing schedules are properly specified and the proper price indices are used.
- Power must be available for delivery under the contract May 1, 2018
- The proposed contract end date is no earlier than April 30, 2033

B. Operating Performance Thresholds

- If the project is located in DEF's system, the Bidder's proposal will be required to show documentation that the following operational criteria can be meet:
  – to operate the project to conform with DEF's ***Voltage Control*** requirements.
  – to operate the project to conform with DEF's ***Frequency Control*** requirements.
  – to be ***Fully Dispatchable*** and install ***Automatic Generator Control*** ("AGC") that is tied into DEF's Energy Control Center **[New and Existing Unit Proposals]**.
- If the project is located outside of DEF's system, New and Existing Unit Proposals must provide documentation to show that the proposal is ***Fully Dispatchable*** and provide ***Dynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.
- The Bidder must show documentation they are willing to ***coordinate the project's maintenance scheduling*** with DEF.
- System Power Proposals must show documentation that the proposal is ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). System Power Proposals must also provide D***ynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.

C. Terms & Conditions Thresholds

- Bidders must agree to each of the Terms & Conditions identified in Attachment A.
  - OR -
- If Bidder has any objections to the Terms & Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

D. Site Control Thresholds [New and Existing Unit Proposals]

- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title (or long term lease) and legal description of the property is required for **Existing Unit Proposals**.

E. Transmission Threshold

- If the proposal is for resources located outside of DEF's system, the Bidder must provide a transmission plan that exclusively utilizes firm transmission service from the host system to the DEF system. Bidders must provide evidence that the host system is willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals. Bidders must provide host utility documentation that the results of a generator feasibility study and/or a host transmission system impact study performed by the host system will be completed or documentation such as a transmission study agreement showing that the results will be available no later than 30 days following the bid submittal date.
- For New Unit Proposals physically located inside the DEF system, documentation that the required Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT has been submitted to DEF **[New Unit Proposals]**.
- The Transmission Information Schedule (Schedule 7 of the Response Package) is properly completed for **All Proposals**.

Minimum Technical Requirements

A. Environmental

* Preliminary environmental analysis performed and submitted to DEF [New Unit Proposals].
* Reasonable schedule for securing permits presented with evidence provided that it is reasonable to expect that permits can be secured in a timely fashion [New Unit Proposals].

B. Engineering and Design

* The project technology is capable of achieving the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].
* Operation and Maintenance Plan provided that indicates the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. Fuel Supply and Transportation Plan

* Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. Project Financial Viability

* For New Unit Proposals, evidence provided that it is reasonable to expect that the project is financially viable (assuming a power purchase agreement is in place with DEF) [New Unit Proposals].
* Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. Project Management Plan

* For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial within the time frame requirements of this RFP [New Unit Proposals].

Table of 2018 RFP Bidder Proposal Resource Scenarios Evaluated in the Company's 2018 RFP Evaluation Process

Scenario	Bid Units	Generic 2018 Units	Backfill Units
1	Citrus CC (NPGU)	None	None
3	Bid C1 Bid A Bid G Bid B	2 CT (188MW each)	2034 450 MW CC 2043 450 MW CC 2044 450 MW CC
5	Bid A Bid G	2x1 CC (793 MW)	2043 450 MW CC 2044 450 MW CC
6	Bid C1 Bid A	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
7	Bid C1 Bid G Bid B	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
8	Bid A	2x1 CC (793 MW) 2 CT (188MW each)	2043 450 MW CC
9	Bid G	2x1 CC (793 MW) 2 CT (188MW each)	2044 450 MW CC
10	Bid C1	2x1 CC (793 MW) 2 CT (188MW each)	2034 450 MW CC
11	Citrus CC (NPGU) Bid B	None	None

Table of the Results of the Company's Initial Detailed Evaluation of the 2018 RFP Bidder Proposal Resource Scenarios

		Differential vs. NPGU $M CPVRR		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($951)	($908)	($773)
TP 5	Bids A and G + Generic CC	($583)	($569)	($438)
TP 6	Bids A and C1 + Generic CC	($512)	($510)	($466)
TP 7	Bids B, C1, and G + Generic CC	($685)	($646)	($620)
TP 8	Bid A + 2 Generic CTs + Generic CC	($376)	($366)	($171)
TP 9	Bid G + 2 Generic CTs + Generic CC	($647)	($631)	($403)
TP 10	Bid C1 + 2 Generic CTs + Generic CC	($457)	($444)	($308)
TP 11	Self-Build NPGU and Bid B	($20)	($4)	($50)

Results of all the Company's Detailed Evaluations of the 2018 RFP Bidder Proposal Resource Scenarios

		Differential CPVRR $2014 in $Millions		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($1,218)	($1,171)	($1,037)
TP 5	Bids A and G + Generic CC	($748)	($731)	($600)
TP 6	Bids A and C1 + Generic CC	($705)	($699)	($655)
TP 7	Bids B, C1, and G + Generic CC	($847)	($811)	($784)
TP 8	Bid A + 2 Generic CTs + Generic CC	($477)	($464)	($269)
TP 9	Bid G + 2 Generic CTs + Generic CC	($718)	($693)	($464)
TP 10	Bid C1 + 2 Generic CTs + Generic CC	($548)	($535)	($399)
TP 11	Self-Build NPGU and Bid B	($29)	($13)	($59)