BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of cost effective generation alternative to meet need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI ORDER NO. PSC-14-0590-FOF-EI ISSUED: October 21, 2014

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
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FINAL ORDER GRANTING DUKE ENERGY FLORIDA, INC.'S DETERMINATION OF NEED FOR THE HINES CHILLERS UPRATE PROJECT

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BY THE COMMISSION:

BACKGROUND

Pursuant to Order No. PSC-13-0598-FOF-EI, issued on November 12, 2013, in Docket No. 130208-EI, In re: Petition for limited proceeding to approve revised and restated stipulation and settlement agreement by Duke Energy Florida, Inc. d/b/a Duke Energy, this Commission approved a Revised and Restated Stipulation and Settlement Agreement (RRSSA) between Duke Energy Florida, Inc. (DEF or Company), the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), the Florida Retail Federation, and White Springs Agricultural Chemicals, Inc. (PCS Phosphate). Portions of that Agreement contemplated the construction or acquisition of new power plants or the upgrade or expansion of existing power plants to address a potential need for generation resources in light of the closure or cancellation of several power plants under the terms of the RRSSA.

On May 27, 2014, DEF filed a Petition and supporting testimony for determination of cost-effective generation alternatives to meet need prior to 2018 (Docket No. 140111-EI) and another Petition to determine the need for a Citrus County Combined Cycle Power Plant (Citrus County Plant) (Docket No. 140110-EI), pursuant to Sections 366.04 and 403.519, Florida Statutes (F.S.), and Rules 25-22.080, 25-22.081, 25-22.082 and 28-106.201, Florida Administrative Code (F.A.C.). If the projects in either docket are placed into service on the projected dates, the terms of the RRSSA permit DEF to recover the costs of the projects through a separate base rate adjustment.

For this docket, DEF's petition consisted of two different projects, the Hines Chillers Power Uprate Project (Hines Project) and the Suwannee Simple Cycle Project (Suwannee Project). The Hines Project involves the installation of a chiller system that will cool the gas turbine inlet air to all four of the existing power blocks at DEF's Hines Energy Center located in Bartow, Florida. The Hines Project has an expected in-service date of summer 2017 and will contribute an additional 220 MW of summer capacity only.

On May 29, 2014, an Order Establishing Procedure was issued for both of the petitions. On May 30, 2014, Calpine Construction Finance Company (Calpine) filed a petition to intervene and OPC filed a notice to intervene for both of the dockets. On June 3, 2014, PCS Phosphate and FIPUG filed a petition to intervene for both dockets. On June 11, 2014, NRG Florida LP (NRG) filed a petition to intervene for both dockets. Intervention for these parties was granted pursuant to several orders.[1] A prehearing conference was held on August 13, 2014, and a formal hearing was held on August 26, 2014 through August 27, 2014. During the hearing DEF made a motion to withdraw a portion of its petition in Docket No. 140111-EI. Specifically, DEF moved to withdraw the Suwannee Project from the petition citing a potential acquisition of Calpine's Osprey Facility in lieu of constructing the proposed Suwannee Project. We granted the motion to withdraw the Suwannee Project from the petition.

This Order only addresses DEF's Petition for determination of cost-effective generation alternatives to meet need prior to 2018 in this Docket. DEF's Petition for a determination of need for the Citrus County Plant, (Docket No. 140110-EI) involving construction of a new power plant at the Crystal River Energy Complex is addressed in Order No. PSC-14-0557-FOF-EI, issued on October 10, 2014, in Docket No. 140110-EI, <u>In re: Petition for determination of need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.</u>

[1] Order No. PSC-14-0301-PCO-EI, issued June 11, 2014 (OPC).
Order No. PSC-14-0306-PCO-EI, issued June 12, 2014 (Calpine).
Order No. PSC-14-0304-PCO-EI, issued June 12, 2014 (PCS Phosphate).
Order No. PSC-14-0305-PCO-EI, issued June 12, 2014 (FIPUG).
Order No. PSC-14-0340-PCO-EI, issued July 3, 2014 (NRG).

DECISION

Jurisdiction

NRG asserts that "Section 403.519, Florida Statutes, is the only source of Legislative authority for this Commission to pre-determine whether a need exists for a proposed power plant and to pre-approve a proposed plant as the most cost-effective alternative to meet that need, and specifically applies only to an electrical power plant subject to the Florida Electrical Power Plant Siting Act. §403.519(1), Fla. Stat." NRG argues that the Florida Electric Power Plant Siting Act[2] (PPSA) narrowly defines what kind of power plants are subject to the act and then grants this Commission the jurisdiction to "pre-determine need" for those plants. According to NRG, the Hines Project is not a power plant as defined under the PPSA, and therefore, is not eligible for pre-approval. Since the PPSA is inapplicable to the Hines Project and since no other statute authorizes this Commission to pre-judge the prudency of the proposed project, the legal maxim "expressio unius est exclusion alterius"[3] applies, and thus this Commission cannot act on DEF's petition at this time. NRG further argues that the RRSSA does not require or allow DEF to initiate this proceeding and merely permits DEF to pursue a prudence review for the Hines Project.

Conversely, DEF argues that this Commission already established its jurisdiction in this matter when it approved the RRSSA pursuant to Chapter 366, F.S. According to DEF, the RRSSA contemplates a Generation Base Rate Adjustment prior to 2018 to address a projected shortfall in generation capacity resulting from the retirement of the Crystal River 3 nuclear power plant and the Crystal River 1 and 2 coal fired power plants along with the cancellation of the Levy nuclear power plant project. As part of the process of obtaining the Generation Base Rate Adjustment, the RRSSA allows DEF to bring a need determination before this Commission. DEF further argues that its petition is not in conflict with this Commission's jurisdiction under the PPSA. Although the PPSA does "carve out" certain kinds of generation resources for need determination proceedings as part of a centralized permitting process, that "carve out" does not conflict with, or diminish, this Commission's existing jurisdiction over projects such as the one proposed in this docket. Furthermore, this Commission is empowered to determine whether or not a matter is within the scope of its jurisdiction.[4] Subject matter jurisdiction arises by virtue of law;[5] if jurisdiction exists, which it does in this matter, then this Commission has jurisdiction regardless of whether the petition or the RRSSA includes a citation to the proper jurisdictional authority. In this instance, DEF asserts that under Chapter 366, F.S., the subject matter in this docket is well within the scope of this Commission's jurisdiction and thus this Commission may render a decision in this matter.

All other parties who offered a position on this matter generally asserted that this Commission would have jurisdiction over the matters proposed in this docket under Chapter 366,

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[2] Section 403.501, F.S. - 403.519, F.S.
[3] "expressio unius est exclusion alterius" or, "the expression of one thing is the exclusion of another"
[4] Florida Public Service Commission v. Bryson, 569 So. 2d 1253, 1255 (Fla. 1990)
[5] Order No. PSC-02-1191-FOF-TP, issued September 3, 2002, in Docket No. 020611-TP, In re: Complaint of BellSouth Telecommunications, Inc. regarding Supra Telecommunications and Information Systems, Inc.'s inappropriate use of Local Exchange Navigation Service (LENS)

F.S., and/or flowing from the jurisdiction that governed the approval of the RRSSA. At the hearing, none of the parties presented any arguments or evidence in support of their position.

NRG posed the question of whether the Hines Project should be heard in this docket. NRG suggests that the PPSA has a specific definition of a power plant, and since the project in this docket does not meet that definition, it is not subject to the PPSA. NRG concludes it is improper for us to act on DEF's petition in this docket because DEF has incorrectly petitioned for this matter to be considered under the PPSA. Thus, the real question is, if the Hines Project is not subject to the PPSA, can we act on DEF's petition in this docket?

To answer this question we first turn to the matter of the RRSSA. The RRSSA was approved by this Commission pursuant to Order No. PSC-13-0598-FOF-EI, issued November 12, 2013, in Docket No. 130208-EI, In re: Petition for limited proceeding to approve Revised and Restated Stipulation and Settlement Agreement, including Certain Rate Adjustments. That Order states that we have jurisdiction over the RRSSA pursuant to Chapter 366, F.S., including Sections 366.04, 366.041, 366.05, 366.06, 366.07, 366.076, 366.8255, 366.93, and 120.57(2) and (4), F.S., and Rules 28-106.301 and 28-106.302, F.A.C.

Paragraph 16 of the RRSSA contemplates DEF's need for increased generating capacity and provides DEF an opportunity to obtain a Generation Base Rate Adjustment to satisfy this need provided any project proposed by DEF under the terms of the RRSSA meets certain minimum standards involving total generating capacity and comes into service prior to 2018. As part of the process for receiving this Generation Base Rate Adjustment, DEF must obtain a need determination so we can determine that there is, in fact, a need for the proposed project and that the proposed project is a prudent solution. Additionally, the RRSSA explicitly states that obtaining the Generation Base Rate Adjustment is "subject to the Intervenor Parties' right to challenge the need for or prudence of any costs associated with the construction, purchase, or acquisition of any such units or uprates." Thus an additional function of the need determination is to satisfy this requirement and allow any interested party the opportunity to review or contest the need for the proposed project regardless of whether that party executed the RRSSA.

Based on the language of the RRSSA and the Order approving it, we find the intent of the RRSSA was to enable DEF to evaluate various generation alternatives and select the most cost-effective option for addressing a perceived need for replacement generation. The RRSSA identified several broad options to address this need including new power plant construction, the uprate or expansion of existing generation resources, or the acquisition of such resources from a third party. Furthermore, the RRSSA contemplated a scenario where DEF would bring its proposed options before this Commission prior to receiving the Generation Base Rate Adjustment. Such a review allows this Commission and any interested party the opportunity to evaluate DEF's evidence that the proposed project is a prudent solution that fills an actual need for additional generating capacity.

Since the RRSSA allows DEF to file a petition for a determination of need, we find that DEF was correct in citing to the RRSSA as a basis for its petition. In doing so, the basis for jurisdiction in Docket No. 140111-EI would include, but not be limited to, the statutes cited as the basis of jurisdiction in the Order that approved the RRSSA.

Turning to Chapter 366, F.S., there are several sections that address the question of our jurisdiction over electric utilities in Florida. In particular, Section 366.04, F.S., titled "Jurisdiction of Commission" states "in addition to its existing functions, the commission shall have jurisdiction to regulate and supervise each public utility with respect to its rates and service." This statute further states that this Commission "in the exercise of its jurisdiction" shall have the authority to prescribe a rate structure for all electric utilities and ensure reliability within an electric grid. As part of its authority over matters affecting the reliability of the electric grid, the statute grants us jurisdiction over the planning, development and maintenance of the electric grid in Florida for operational purposes and to avoid the "uneconomic duplication of generation, transmission and distribution facilities."

Furthermore, there are numerous other sections of Chapter 366, F.S., that grant us authority over this matter. Section 366.05, F.S., states that "in the exercise of such jurisdiction, the commission shall have power to prescribe fair and reasonable rates and charges, classifications, standards of quality and measurements." Section 366.041, F.S., provides that in fixing rates this Commission may consider "among other things, to the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered." Section 366.055, F.S., states that this Commission has the authority to ensure grid reliability and integrity is maintained. Sections 366.06, F.S., and 366.07, F.S., describe the procedure and authority for fixing and adjusting the rates charged by electric utilities.

This statutory language is unambiguous. Chapter 366, F.S., establishes our jurisdiction over any matter that affects the rates and services of electric utilities in Florida, or for preventing the uneconomic duplication of generation, transmission or distribution resources. Our jurisdiction also extends to matters that would affect the reliability of the electric grid. When we apply the facts presented in this docket to the statutory authority granted to this Commission under Chapter 366, F.S., we find the Hines Project would clearly have an effect on the reliability of the service provided by DEF, as well as the on the reliability of the electric grid. As stated in the RRSSA, if the Hines Project is put into service, it would be entered into the rate base and would, therefore, affect the rates of DEF. The Hines Project would also merit scrutiny to determine that there is a need for the project in order to establish that it would not constitute the uneconomic duplication of generation resources. In short, we find that the Hines Project is squarely within the boundaries of regulating electric utilities for which this Commission has been expressly granted jurisdiction by the Florida Legislature pursuant to Chapter 366, F.S.

Furthermore, our authority enables us to hear any matter within our jurisdiction upon our own motion or upon the request of an interested third party, particularly with regard to any matter that involves fixing or adjusting rates as stated in Section 366.06(2), F.S., and Section 366.07, F.S. We find that, had DEF filed its petition for a determination of need without citation to the RRSSA or if we assume for the sake of argument that DEF incorrectly cited Section 403.519, F.S., as the sole basis for Commission jurisdiction, it is clearly within our discretion and authority to address DEF's petition under the broad jurisdiction granted under Chapter 366, F.S.

Therefore, pursuant to Chapter 366, F.S., we have the jurisdiction to grant or deny DEF's petition for a determination of need that the Hines Project is a cost-effective generation alternative to meet DEF's needs prior to 2018.

Need for Electric System Reliability and Integrity

DEF argues that the undisputed evidence demonstrates that the Hines Project assists DEF in meeting its commitment to maintain a minimum 20 percent reserve margin to maintain electric system reliability and integrity. DEF asserts that its need for the Hines Project is driven by generation facility retirements and power reductions, and projected increases in summer firm demand and energy growth in 2016 and 2017. DEF lastly states that no intervenor presented any evidence disputing DEF's evidence that DEF has a reliability need for additional generation capacity on DEF's system prior to 2018.

NRG argues that DEF has not met its burden of proof that it needs any additional generation in 2018 to meet its reserve margin. NRG asserts that DEF's projected load growth is far more load growth than DEF has experienced in any two consecutive years since 2005. NRG further contends that DEF has not demonstrated that its forecast is reasonable or that this high level of load growth is likely to materialize. NRG opines that the record reflects DEF has consistently overestimated its actual need. NRG further attests that DEF's 2013 Ten-Year Site Plan overestimated its actual 2013 need by 881 MW. NRG expresses trepidation that DEF modeled sensitivities to changes in gas price and carbon costs, but failed to model the effect of an inaccurate load forecast.

NRG also argues that even assuming that DEF needed its full forecasted capacity, DEF's withdrawal of the Suwannee peaker project and its newly-announced decision to keep the existing 129 MW Suwannee steam plants in service while purchasing power from and pursing acquisition of Calpine's Osprey Facility would provide DEF with 316 MW more than the net 412 MW of generation it would have gained by building the Hines Project and Suwannee Project. No other party addressed the reserve margin issue.

As proposed, the Hines Project will contribute 220 MW of summer capacity. The current plan is for the four blocks of chillers to come into service in alignment with upcoming outages at DEF's Hines Energy Center with all four blocks being in service by the summer of 2017.

Based on current projections DEF Witness Borsch contends that DEF needs additional generation in the summer of 2016 and 2017 to meet its 20 percent minimum reserve margin requirement. Witness Borsch testified that DEF's projected needs prior to 2018 are a result of load growth, planned unit retirements, and unit de-rates.

Load Forecast

DEF's load forecast presented in this proceeding is the same forecast that appears in DEF's 2014 Ten-Year Site Plan. DEF forecasts its future load requirements by utilizing statistical modeling techniques. In order to model and forecast load, DEF makes certain assumptions relating to factors that influence energy consumption and demand. DEF's assumptions for forecasting load can generally be described as economic, demographic, and weather related. The demographic and weather related assumptions are what DEF refers to as "General Assumptions." General Assumptions include accounting for normal weather, population and average household size, production conditions/environment concerning phosphate mining, wholesale contracted load, demand side management, and the amount of cogeneration expected by its customers. Economic related assumptions such as inflation, employment, and income are also utilized to model and forecast load requirements.

DEF utilizes its forecast assumptions to produce projections of customer, energy, and peak demand requirements, through the application of both econometric and end-use modeling methodologies. We note the econometric modeling approach attempts to explain (and thus predict) DEF's energy and demand requirements as a function of relevant (demographic, economic, and weather) variables. The end-use, or statistically adjusted end-use approach, attempts to determine and refine projections of future demand by modeling new and upcoming industry regulations and the characteristics of new electricity-driven devices.

According to DEF's 2014 Ten-Year Site Plan, once customer, energy, and peak demand models are formulated, an overall evaluation process commences. After evaluation, preliminary customer, energy, and demand forecasts are produced. These preliminary forecasts are then evaluated by DEF's Senior Management. Following review by Senior Management, DEF releases its official customer, energy, and demand forecasts. These final forecasts provide the basis for DEF's demand and system requirements.

DEF contends that there will be a need for additional generation capacity on its system prior to 2018. Witness Borsch stated "[b]y the summer of 2018...the summer peak demand is projected to grow to 9,439 MW and by the next summer...the summer peak demand is projected to reach 9,813 MW." DEF's forecast presented in this docket represents an annual growth rate of approximately 1.4 over the next ten year projected period.[6]

Witness Borsch further testified that the Company's system energy requirement, or net energy for load, is also projected to increase over the same time period due to increasing customer growth and Florida's general improving economic conditions. Net energy for load is expected to grow from 39,801 GWh in 2014, to 41,995 GWh in 2018, or by 2,194 GWh over the period. While net energy for load is expected to grow to 43,013 GWh by 2019 or by 3,212 GWh from 2014 – 2019.

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[6] See Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, In re: Generic investigation into aggregate electric utility reserve margins planned for Peninsular Florida.

We note, however, that NRG Witness Pollock's Exhibit 85, which details the impact of limiting DEF's net firm summer peak demand to reflect only achieving 50 percent of its projected growth spanning the timeframe of 2014 – 2023. Witness Pollock's testimony characterizes this 50 percent load growth adjustment as an illustration of potential forecasting error.

One issue concerning DEF's load forecast is the potential for forecast error and associated magnitude. No intervenor filed a load forecast. We find the primary assumptions of DEF's load forecast are economic, demographic, and weather related. Furthermore, these are proper inputs and necessary assumptions for modeling and forecasting the future demand and energy needs of the Company's customers. Concerning intervener testimony filed in this docket, Witness Pollock suggested the possibility of error in DEF's forecast without clearly defining a basis for either its magnitude or direction. We understand the deviation in projected summer peak demand may be arbitrary. However, to assess the reasonableness of assumptions by NRG, we compared DEF's forecasts to the adjusted forecasts set forth by Witness Pollock, see Table 1 below:

Table 1: DEF Net Summer Firm Demand Forecast Compared with Hearing Exhibits 85 and 140

Year	DEF[7]	NRG[8]	Percent Difference, NRG to DEF	PCS[9]	Percent Difference, PCS to DEF
2014	8,812	8,411	(4.55%)	8,068	(8.44%)
2015	9,042	8,525	(5.72%)	8,207	(9.23%)
2016	9,149	8,579	(6.23%)	8,331	(8.94%)
2017	9,307	8,658	(6.97%)	8,387	(9.89%)
2018	9,440	8,725	(7.57%)	8,513	(9.82%)
2019	9,813	8,911	(9.19%)	8,719	(11.15%)
2020	9,935	8,973	(9.68%)	8,919	(10.23%)
2021	9,952	8,980	(9.77%)	9,004	(9.53%)
2022	10,067	9,039	(10.21%)	9,095	(9.66%)
2023	10,173	9,092	(10.63%)	9,215	(9.42%)
2014 - 2023 Average Variation			(8.05%)		(9.63%)

To the extent Witness Pollock raises general issues surrounding forecast error potential, projections will usually differ from actuality, we concur. The level of forecast error for the relevant year of 2017 is 50 percent. NRG provided no basis for selecting a 50 percent reduction

[7] Hearing Exhibit Number 49.
[8] Hearing Exhibit Number 85.
[9] Hearing Exhibit Number 140.

to DEF's Net Summer Firm Demand Forecast. In as much as NRG did not file an alternative firm summer peak demand forecast, we interpret this Exhibit to be illustrative in nature, highlighting what NRG proffers as a possible forecast error.

Table 1 displays NRG's exhibit relative to DEF's net summer firm demand forecast, which yields a forecast deviation of 6.97 percent from DEF's total projected amount for 2017. We compared this illustrative forecast error to DEF's 2009 forecast error of 2012 demand, which was 7.1 percent. We find this is relevant because they both represent a four year range, thus the forecast error percent in both these instances is comparable. The 2009 Ten-Year Site Plan variance of 2012 demand can largely be attributed to a weak economic recovery stemming from the unforeseen effects of the great recession and associated housing market decline. There is no record evidence to indicate the economic circumstances of 2008-2009 are currently present that would impact DEF's forecasted demand. We find DEF's load forecast presented in this docket is reasonable for the purposes of determining the need for DEF's proposed Hines Project.

Total Capacity

Prior to 2017, DEF plans to retire combustion turbines at the Company's Avon Park, Turner, and Rio Pinar sites. These combustion turbines were installed in the late 1960's and early 1970's and have been identified for retirement in the Company's resource planning process since the late 2000's. Collectively these units provide 133 MW of summer generation capacity to DEF's system. Witness Borsch testified that these units are becoming more costly to operate and maintain.

DEF indicated that the combustion turbines, noted above, burn mainly distillate oil and have heat rates ranging from 15,300 to 18,800 btu/kwh and are sometimes up to ten times more expensive to dispatch versus natural gas-fired generation. DEF stated that, due to the advanced age of these units, the Company has been forced to revert to secondary sources (salvage part suppliers, parts remanufacturers, E-Bay, etc.) to keep the units available in case they are needed to support the grid. We find that the retirement of these units is a reasonable decision at this time.

For evaluation purposes, DEF also assumed the retirement of its Suwannee 1-3 steam units (129 MW) and the construction of the Suwannee Project (316 MW). DEF announced a potential purchased power agreement (PPA)/acquisition of Calpine's Osprey Facility in lieu of constructing the proposed Suwannee Project in 2016, and the continued operation of Suwannee Units 1-3. We find that the Osprey Facility would only be capable of providing 249 MW, of its rated 515 MW output, to DEF prior to 2020.

Based on the evidence in the record, we recalculated DEF's originally filed reserve margin to ensure that the Company still has a reliability need in 2017. Table 2, below, shows that DEF's reserve margin in 2017 would fall to 19 percent absent any new generation. This represents a 94 MW need. Although, the need is relatively small, Witness Borsch testified that the addition of the Hines Project is cost-effective even when the capacity of the project was not needed to meet the Company's reserve margin criteria. We also note that no party in this docket disputed the need for the Hines Project.

Table 2: Reserve Margin Without the Hines Project[10]

	Peak Demand (MW)	Installed Capacity (MW)	Reserve Margin
2014	8,812	11,024	25.1%
2015	9,042	10,991	21.6%
2016	9,149	11,074	21.0%
2017	9,307	11,074	19.0%

Given a 20 percent reserve margin criterion, we find that the evidence in the record demonstrates a need for the Hines Project beginning in 2017. Based on our calculations, if DEF did not construct the proposed Hines Project in 2017, the projected reserve margin could fall below the Company's 20 percent criterion.

Conclusion

If DEF did not construct the proposed Hines Project in 2017, the projected reserve margin could fall below 19 percent. Although, the need is relatively small, the record demonstrates that the addition of the Hines Project is cost-effective even when the capacity of the project was not required to meet the reserve margin.

Need for Adequate Electricity at Reasonable Cost

DEF argues that the undisputed evidence demonstrates that the Hines Project will provide DEF's customers needed summer peaking capacity at a reasonable cost. DEF asserts that the estimated project cost is $160 million and when complete will increase summer capacity by approximately 220 MW. DEF further explains that there will be a minimal increase in the fixed and variable Operations and Maintenance (O&M) costs at the Hines Energy Center. DEF concludes that the Hines Project, therefore, provides DEF's customers adequate electricity at a reasonable cost.

NRG contends that the Hines Project is unreasonably expensive on a per-kW basis. NRG suggests that the nominal cost of the Hines Project is misleadingly low because it will only contribute power to meet DEF's summer peak. NRG argues that the Hines Project per-kW price increases dramatically when adjusted to reflect its limited availability. NRG submits that assuming that the project will contribute 220 MW to DEF's system 50 percent of the time, the per-kW price increases dramatically to $1,450.

OPC, FIPUG, and Calpine did not file arguments directly related to the information discussed in this matter. PCS Phosphate did not disagree with DEF on this issue and as a result did not present any arguments against DEF.

According to DEF Witness Landseidel, The Hines Project consists of installation of chiller modules for the existing Hines Energy Center power block units, a large chilled water

[10]Commission staff Calculation Based on Hearing Exhibit No. 65

storage tank, an auxiliary power system, pumps and chilled water supply and return piping, and gas turbine air inlet chiller coils. The installation of the chiller system on the existing Hines Energy Center power block units (Hines Units 1-4) is designed to cool the gas turbine inlet air thus increasing the capacity of each power block while maintaining fuel efficiency. Hines Units 1-4 have a total installed capacity of approximately 1,900 MW. When complete, the Hines Project will increase the summer capacity of those units by approximately 220 MW. Witness Landseidel also presented testimony and exhibits regarding cost estimates and performance projections of the Hines Project. He further testified that existing generation, site infrastructure, and transmission infrastructure will support the power Uprate project and that there is no transmission costs associated with the Hines Project.

Financial Assumptions

DEF used a capital structure consisting of 50 percent equity at cost rate of 10.50 percent and 50 percent debt at a cost rate of 3.75 percent. DEF applied an after-tax discount rate of 6.46 percent based on the effective income tax rate of 35.26 percent. No evidence was presented in the record disputing the reasonableness of these financial assumptions. We find that the financial assumptions used for this evaluation are reasonable.

Generation Cost Estimates and Projected Performance Specifications

DEF estimates the total project cost of the Hines Project to be $160 million. DEF indicated that Kiewit Power Engineers, the engineer of record for two of the Hines power blocks, assisted in putting together the preliminary estimate for the Hines Project. DEF additionally asserted that an inlet chiller package supplier with experience in retrofit inlet chilling projects provided indicative pricing that further supported the capital cost estimate. According to DEF this advice, together with the Company's project and estimating experience, provided the basis for the cost estimate. Based on a response to Commission staff discovery, the projected cost of the Hines Project is comparable to a similar project installed at the Duke Energy Carolinas Dan River Combined Cycle project. Witness Landseidel testified that the Hines Project will increase summer capacity with a minimal increase in the fixed and variable O&M costs at the Hines Energy Center.

Fuel Costs

DEF's fuel price forecasts were presented by DEF witness Delehanty and in response to Commission staff discovery. DEF's fuel price forecasts of natural gas, coal, and distillate oil represent a combination of short-term fuel price forecasts and long-term fuel price forecasts. The Company's short term forecast is based on available futures market prices, spot market prices, and short-term contract prices. The Company's long term forecast is a forward-looking evaluation of the marginal cost of supply at the expected level of demand, prepared with the assistance of DEF's current industry consultant, Energy Ventures Analysis, Inc.

DEF worked collaboratively with Energy Ventures Analysis, Inc. to ensure that the assumptions and data inputs in its long term commodity price forecasts were consistent with DEF's internal planning assumptions and data inputs. DEF's low and high natural gas price forecasts scenarios were developed by comparing the DEF Energy base natural gas price forecast to recent, recognized industry natural gas price forecasts and applying statistically relevant standard deviations to the data. The low natural gas price forecast is 18 percent lower and the high natural gas price forecast is 14 percent higher than DEF's base natural gas price forecast. No party took a position opposing DEF's fuel price forecasts. We have reviewed the record evidence pertaining to DEF's base, high, and low fuel price forecasts and find they are reasonable projections of fuel prices for the relevant forecast horizon.

Environmental Costs

DEF has consistently included the cost of carbon dioxide (carbon) in its base case for planning purposes since 2006. DEF believes that it is prudent to model a price on carbon as a way of capturing the risk of potential future legislation and pending Environmental Protection Agency regulation of carbon, as well as the impact of a national carbon policy. In order to test the reasonableness of its carbon cost forecast, DEF reviewed carbon dioxide cost estimates from the Energy Information Agency and cost estimates from the failed Waxman-Markey bill. DEF asserted that the carbon price it currently uses is a reasonable representation of the risk arising from federal climate change legislation or regulation given the current uncertainty surrounding such policy. We note that neither the appropriateness for DEF to include the projected carbon cost in its base case of the resource planning nor the actual carbon price used by DEF was challenged by any of the parties in this docket. DEF also performed a zero-price carbon case sensitivity analysis as an alternative to its base case. The results of such analyses show that the Hines Project remains the most cost-effective resource for DEF's customers.

Rate Impact

DEF projected a residential base rate increase of approximately $0.61 on a 1,000 kWh bill when the Hines Project is placed in service. Paragraph 16(a) of the RRSSA states:

> DEF shall have the ability to recover the full, prudently incurred revenue requirement of any: (1) combustion turbine unit(s) constructed and associated transmission required to integrate and deliver power from such unit(s) into the DEF system; (2) any power uprates to existing DEF unit(s); and/or (3) any existing combustion turbine and/or combined cycle unit(s) acquired or purchased along with any transmission costs required to integrate and deliver power from such unit(s) into the DEF system, not to exceed a total megawatt ("MW") capacity of 1150 MWs collectively for items (1), (2) and/or (3) above (unless a higher MW amount is otherwise agreed to by the Parties), which may be placed in-service and/or acquired/purchased prior to year-end 2017, through a base rate increase at the time each unit is placed in service and/or acquired/purchased. In addition, DEF will evaluate and compare whether it is more cost effective to satisfy this MW capacity need prior to 2017 through its Integrated Resource Planning ("IRP") methodology and will provide this comparison at the time it submits these costs in (1), (2) or (3) of this paragraph for prudence review.

Therefore, if in-service date of the Hines Project is delayed beyond 2018, for any reason, the base rate increase, per the settlement, would not be applicable.

Conclusion

We find that DEF's assumptions and forecasts in its analysis of the proposed Hines Project are reasonable for evaluation purposes.

Need Based on Fuel Diversity and Supply Reliability

DEF argues that the undisputed evidence demonstrates that the Hines Project is needed when taking into account the need for fuel diversity and supply reliability. DEF contends that natural-gas fired generation is the most economic and qualitatively attractive generation technology for DEF and the State of Florida at this time and for the foreseeable future. DEF further asserts that there are abundant conventional and unconventional natural gas supply resources available in the United States and North America. DEF states that these natural gas supply resources ensure a long term natural gas supply at economically beneficial prices for electric power generation at the Hines Energy Center.

OPC, FIPUG, and Calpine did not file arguments directly related to the information discussed in this matter. PCS Phosphate did not disagree with DEF on this issue and as a result did not present any arguments against DEF.

Based on the current assumptions, DEF's energy generation from natural gas is projected to increase from 56.6 percent in 2013 to 66.2 percent in 2019. Witness Borsch testified that new coal-fired generation is not feasible at this time given environmental constraints. Additionally, DEF asserted that additional coal generation would generally take six to seven years to construct while new nuclear generation would require at least ten years, which is beyond DEF's projected need prior to 2018.

We find that natural gas generation is the only reasonable generation option to meet DEF's needs at this time. DEF's Hines Project will increase the summer output of four of the Company's most efficient units, thus increasing the efficiency of the Company's overall system. DEF indicates that the efficiency of the proposed Hines Project will result in reduced fuel and emissions costs that would have resulted from energy generated from less efficient generation resources such as combustion turbines. The reduced fuel cost provides a level of protection with respect to fuel volatility which is a benefit of fuel diversity. Therefore, we find that increasing the capacity of efficient combined cycle generation is a means for providing fuel diversity.

Conclusion

We find that the Hines Project will increase the overall efficiency of DEF's generation fleet. We further find that the increased efficiency will reduce fuel costs and will provide benefits with respect to mitigating the impacts to fuel cost volatility.

<u>Renewable Energy Sources, Technologies, or Conservation Measures</u>

DEF claims it has provided undisputed evidence that demonstrates that there are no renewable energy sources or conservation measures that would mitigate the need for the Hines Project. DEF argues that it analyzed non-generating, demand side alternatives and still found that the Hines Project was more cost-effective. DEF also states that despite having an ongoing Request for Renewables (RFR), it did not receive any renewable resources or technologies that would mitigate the need for additional generation capacity in 2016. DEF also argues that it considered energy conservation, direct load control programs and its current Demand Side Management (DSM) programs but there was still a need for additional generation capacity in 2016.

NRG argues that this Commission should defer its ruling in this proceeding because DEF has proposed new conservation goals that are currently waiting for approval. OPC, FIPUG, and Calpine did not file arguments directly related to the information discussed in this matter.

DEF determined its future demand and energy needs for 2017 based on an IRP process. DEF's load forecast developed during the IRP process incorporated all demand and energy reductions expected from DEF's current DSM programs.

For analysis purposes, DEF assumed that its current DSM programs would continue; however, DEF has proposed new DSM goals that are presently under review and pending approval by this Commission in Docket No. 130200-EI. If approved, Witness Borsch asserts that the proposed goals will slightly accelerate the need for new generation for the study period, because the proposed goals are lower than the existing goals; by 2017, the cumulative difference between the existing and proposed goals would be 72 MW. Therefore, DEF was conservative in this proceeding by assuming greater DSM savings than the Company is currently seeking approval for.

DEF has maintained an open RFR that was first issued on July 19, 2007. Despite having the ongoing RFR, DEF claims there are not any renewable resources commercially available at a utility-scale for generation capacity at a cost-effective price. DEF also kept its 2018 Request for proposals (RFP) open to proposals for other types of resources besides gas-fired generation, but only gas-fired proposals were received with the exception of a small existing non-solar renewable generation facility. DEF's load forecast included all of its current firm renewable contracts that extend beyond 2018 and contribute over 450 MW of power a year. For planning purposes, DEF does not include any of its non-firm renewable contracts such as its solar resources in its forecast because they cannot be counted on to meet the reliability needs of the Company.

<u>Conclusion</u>

We find that DEF's IRP process used to determine its resource need fully takes into account all projected DSM benefits based on its existing Commission approved programs.

DEF's ongoing RFR did not identify any renewable resources that could possibly mitigate DEF's capacity needs in 2017.

Cost Effectiveness

DEF argues that the uncontroverted evidence demonstrates that the Hines Project is the most cost-effective alternative available to meet a portion of the need of DEF and its customers prior to 2018. DEF asserts that it evaluated new generation, existing plant uprate projects, and existing generation life extension projects to meet this need. DEF explains that this evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options.

DEF contends that it systematically followed a structured, orderly evaluation process that evaluated nine proposals, including the Company's self-build generation projects, on price and non-price attributes, including all generation, environmental, and transmission cost impacts. DEF concludes that this detailed evaluation analysis demonstrated that the Hines Project was cost-effective in every generation alternative resource combination to meet DEF's need prior to 2018.

NRG argues that because the load forecast is an integral assumption of DEF's cost-effectiveness analysis, its failure to model high and low case forecasts means that there is no basis to conclude that any generation portfolio presented in this case is the most cost-effective alternative for ratepayers. No other party took issue with DEF's position in this matter.

DEF's original filing requested approval of the Hines Project and the Suwannee Project. At the August 26, 2014, hearing DEF withdrew its request for approval of the Suwannee Project and decided to pursue approval of the Hines Project, to be constructed to meet a portion of DEF's need prior to 2018. Witness Borsch testified that DEF received nine proposals for PPAs or generation facility acquisitions from seven participants.

DEF performed an initial detailed economic optimization analysis comparing the proposals against the Company's self-build option which included the Suwannee Project and three Hines chillers. DEF later determined it was feasible to add inlet chillers to all four Hines power blocks. Witness Borsch explained that the optimization analyses assessed the impact of each proposal on total system costs including the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs.

During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Project. In each case, addition of the Hines Project was more favorable from a Cumulative Present Value of Revenue Requirements (CPVRR) perspective, even when the capacity of the Hines Project was not required to meet DEF's reserve margin criterion. As a result, all of the resource plans included inlet chilling at the Hines Energy Center. The Hines Project meets DEF's need for reliable capacity through an increase in the efficiency of the existing natural gas-fired, combined cycle plants. The project produces the savings associated with achieved reliable summer peaking capacity of combined cycle generation efficiency without having to build additional peaking capacity at another site on DEF's system. The analysis of the Hines Project in the acquisition cases show that the project provides savings of $90 to $140 million.

The fuel efficiency and relatively low cost of the Hines Project make it a highly cost-effective generation option to meet DEF's customer reliability needs. None of the witnesses contested the cost-effectiveness of the Hines Project to meet DEF's generation capacity need commencing in the summer of 2017. DEF will be saving customers the increased cost and time building new generation at another existing site or greenfield site to achieve the same reliable summer capacity. There will be a minimal increase in the fixed and variable O&M costs at DEF's Hines Energy Center and much lower fixed and variable O&M costs for the same amount of capacity for a new power plant at an existing or greenfield site.

Conclusion

We find that the proposed Hines Project is a cost-effective option for DEF to satisfy part of its need prior to 2018. We find that DEF's analysis of multiple scenarios indicate a high likelihood that the proposed project will result in savings for DEF's customers. Based on DEF's analysis, the Hines Project will provide a savings of $90 to $140 million.

Evaluation of Alternative Scenarios for Cost Effectiveness

DEF argues that it reasonably evaluated all alternative scenarios to the Hines Project for cost-effectively meeting a portion of DEF's need prior to 2018. DEF explains that its evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options. DEF asserts that it followed a structured, orderly evaluation process that evaluated all proposals, including the Company's self-build generation projects, on all price and non-price attributes, in evaluating nine proposals for PPAs or generation facility acquisitions.

NRG argues that the plan DEF is now pursuing will result in a net increase of over 500 MW more than it originally sought. NRG further asserts that in the absence of further evidentiary proceedings in which this matter may be fully evaluated and evidence presented by DEF to this Commission demonstrating that it has met its burden in this regard, this Commission should conclude that DEF failed to reasonably evaluate all alternative scenarios.

OPC, FIPUG, and Calpine did not file arguments directly related to the information discussed in this matter. PCS Phosphate did not disagree with DEF on this issue and as a result did not present any arguments against DEF.

Witness Borsch provided testimony and exhibits discussing DEF's economic evaluation of scenarios to meet its projected need prior to 2018. Witness Borsch testified that DEF issued a solicitation for proposals for PPAs for which bids were initially received in October 2012. Following DEF's initial solicitation the Company implemented a plan to continue the operation of Crystal River Units 1 and 2 to 2018. Witness Borsch testified that this plan substantially reduced the Company's needs prior to 2018. Potential suppliers submitted renewed bids for

PPAs and generation facility acquisition offers to meet DEF's near-term generation capacity needs in September and October 2013. Evidence in the record further demonstrates that DEF continued negotiating with Calpine as well as NRG.

Witness Borsch testified that DEF received nine proposals for PPAs and generation facility acquisitions from seven participants. DEF performed an initial detailed economic optimization analysis comparing the proposals against the Company's self-build option which included the Suwannee Project and three Hines chillers. DEF later determined that it would be feasible to add inlet chillers to all four Hines power blocks. DEF utilized the Strategist resource optimization program to perform the Company's economic evaluation of the proposed Hines Project. Witness Borsch testified that the Strategist model is a utility accepted industry production cost model. Inputs to the Strategist model include the costs and operational characteristics of generating units. Witness Borsch asserted that the optimization analyses were performed for a period of 30 years, and explained that the optimization analyses assessed the impact of each proposal on total system costs including the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs.

During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Project. In each case, addition of the Hines Project made the project more favorable from a CPVRR perspective, even when the capacity of the Hines Project was not required to meet DEF's reserve margin criterion. As a result, all of the resource plans include the Hines Project.

Conclusion

We find that DEF used reasonable assumptions in its evaluation that determined that the Hines Project will result in savings to customers.

Determination of Need

DEF argues that the undisputed record evidence demonstrates that the Hines Project will meet a portion of DEF's need prior to 2018 in a cost-effective manner. DEF contends that the fuel efficiency and relatively low cost of the Hines Project make it a highly cost-effective generation option to meet DEF's customer reliability needs. DEF additionally asserts that the addition of the Hines Project to every generation capacity resource proposal made every proposal more economically favorable for DEF's customers. DEF concludes that this Commission should grant DEF's Petition and approve the Hines Project as the most cost-effective generation alternative to meet a portion of DEF's customer needs prior to 2018.

OPC submits that this Commission should hold DEF to the same standard that will apply to the Citrus County Plant which is the subject of a petition for need determination in Docket No. 140110-EI under the provision of Paragraph 16 of the RRSSA and Rule 25-22.082(15), F.A.C. OPC asks this Commission to accept DEF's representation and indicate that the agency expects DEF to, first, not exceed the construction estimate of $160 million and, second, if they do experience a cost overrun, that this Commission will expect DEF not to seek recovery unless they can meet the same standard as in subsection 15 of Rule No. 25-22.082 F.A.C (Bid Rule) to which Witness Borsch essentially committed in the hearing.

FIPUG states that DEF must meet its burden of proof to demonstrate that the Hines Project is needed. NRG took a position opposed to DEF's. Calpine took a position similar to DEF. PCS Phosphate took no position on this matter; however, PCS Phosphate did indicate that it supports DEF's proposal to move forward with the Hines Project.

The following is a summary of our review of the Hines Project:

1. DEF's load forecast in this proceeding is reasonable.

2. No cost-effective DSM or renewable resources have been identified that could mitigate the need for the Hines Project.

3. The Hines Project is expected to provide adequate electricity at a reasonable cost to DEF's customers.

4. The Hines Project will increase the efficiency of DEF's system.

5. DEF performed a reasonable evaluation of alternatives to the Hines Project.

6. DEF's Analyses indicate that the Hines Project is the most cost-effective alternative compared to respondents to DEF's RFP.

Therefore, upon consideration of all of the evidence presented in this docket, we grant the requested determination of need since the proposed Hines Project represents an optimal resource option to meet DEF's projected need prior to 2018.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the petition for determination of need, filed by Duke Energy Florida, Inc., is hereby granted as set forth herein. It is further

ORDERED that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that this docket shall be closed if no appeal is timely filed.

By ORDER of the Florida Public Service Commission this 21st day of October, 2014.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

MTL

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.