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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination that the Osprey Plant Acquisition and, alternatively, the Suwannee Simple Cycle Project is the most Cost Effective Generation Alternative to meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.	))))))))	DOCKET NO. ______________ Submitted for filing: January 30, 2015

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING

Duke Energy Florida, Inc. ("DEF" or the "Company") hereby gives notice of filing the Direct Testimony Exhibits BMHB-2 through BMHB-4 of Benjamin M.H. Borsch in support of DEF's Petition for Determination that the Osprey Plant Acquisition and, Alternatively, the Suwannee Simple Cycle Project is the Most Cost Effective Generation Alternative to Meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.

Respectfully submitted this 30th day of January, 2015.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

DOCKET NO. 140111-EI
Submitted for filing:
August 5, 2014

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REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

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

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. 140111-EI

REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH

I. INTRODUCTION AND PURPOSE OF REBUTTAL TESTIMONY.

Q. Please state your name 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. What is your position with Duke Energy?

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"). In my capacity as Director, IRP & Analytics --- Florida I was responsible for the Company's Integrated Resource Planning ("IRP") process that identified DEF's need for reliable generation capacity prior to 2018 and that led to the selection of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternative to meet DEF's need prior to 2018.

Q. Have you previously filed direct testimony in this Docket?

A. Yes. I filed direct testimony and exhibits on May 27, 2014 in support of the Company's Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

Q. Have any intervenors filed direct testimony in this docket?

A. Yes. Calpine Construction Finance Company, L. P. ("Calpine") and NRG Florida LP ("NRG") have intervened and filed direct testimony in this Docket. Calpine filed on its behalf in this Docket the direct testimony of Todd Thornton, John Simpson, Paul Hibbard, and Dr. David Hunger. NRG filed on its behalf in this Docket the direct testimony of Jeffry Pollock, Jim Dauer, and Dr. John Morris.

Q. Have you reviewed the direct testimony filed by Calpine and NRG in this Docket?

A. Yes. I reviewed the direct testimony and exhibits filed by both Calpine and NRG in this Docket. NRG filed the exact same direct testimony and exhibits in this Docket that NRG filed in Docket No. 140110-EI, which is the proceeding addressing the Company's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant. Calpine also filed the exact same direct testimony and exhibits for witnesses Mr. Simpson and Mr. Hibbard in this Docket that Calpine filed in Docket No. 140110-EI, and Calpine filed slightly different direct testimony in this Docket for Calpine witness Mr. Thornton than what Calpine filed for Mr. Thornton in Docket No. 140110-EI. My rebuttal testimony in Docket No. 140110-EI addresses the direct testimony and exhibits filed by the Calpine and NRG witnesses in that Docket. The purpose of this rebuttal testimony is to respond to the direct testimony, exhibits, and recommendations of the Calpine and NRG witnesses in this Docket.

II. ORGANIZATION AND SUMMARY OF REBUTTAL TESTIMONY.

Q. How is your rebuttal testimony organized?

A. The first part of my rebuttal testimony in this Docket addresses Calpine's and NRG's new and different proposals to meet DEF's customer needs for generation capacity prior to 2018. To explain briefly, the Calpine witnesses rely in their direct testimony on a proposal to meet DEF's need prior to 2018 that was submitted to DEF after DEF filed its direct testimony and exhibits in this Docket. This proposal is different from the Calpine proposal that was submitted to and evaluated by DEF, and that is discussed in my direct testimony and exhibits in this Docket. NRG likewise submitted a new and slightly different proposal from the proposal that was submitted to, evaluated by, and addressed by DEF in my direct testimony and exhibits, but it is not clear from NRG's testimony which proposal NRG is now relying on in its direct testimony and exhibits in this Docket. In any event, the first part of my rebuttal testimony explains the history behind why Calpine and NRG made these different, alternative proposals, the discussions between the parties related to these and other proposals made to DEF after DEF filed its Petition, direct testimony, and exhibits in this Docket, and DEF's evaluation of these different, alternative proposals that demonstrates that, despite NRG's and in particular Calpine's efforts to close the gap between their initial proposals and DEF's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project, their revised proposals, on a quantitative and qualitative basis, still are not the most cost effective generation alternative to meet DEF customer needs prior to 2018.

Q. How is the rest of your rebuttal testimony organized?

A. I will also address the evidence presented by DEF in support of its Petition in this Docket that is uncontested by any witness, and the evidence that is not disputed by any Calpine or NRG witness, respectively. I believe this discussion of the uncontested DEF evidence is helpful in focusing the Commission on the issues that are really in dispute in this Docket.

Next, I will address the Calpine and NRG witness criticisms about DEF's quantitative and qualitative evaluation of the most cost effective generation alternative to meet DEF's need prior to 2018. This includes their criticisms regarding the evaluation methodology and the quantitative and qualitative factors that DEF considered in that evaluation, including firm natural gas transportation reliability and costs, transmission reliability and costs, and the Federal Energy Regulatory Commission ("FERC") Competitive Analysis Screen. DEF witnesses Jeff Patton and Ed Scott have also filed rebuttal testimony addressing the intervenors' criticisms of DEF's quantitative and qualitative assessment of firm natural gas transportation and transmission reliability and costs, respectively, in DEF's evaluation of the most cost effective alternative to meet DEF's need prior to 2018. In addition, Julie Solomon with Navigant Consulting, Inc. has filed rebuttal testimony addressing the NRG and Calpine direct testimony about the FERC Competitive Analysis Screen.

Finally, I will summarize the quantitative and qualitative benefits to DEF's customers of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project compared to the Calpine and NRG alternative generation capacity proposals. Simply put, considering all quantitative and qualitative factors, the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost effective generation alternative to meet DEF's customer needs prior to 2018.

Q. Please provide a brief summary of your rebuttal testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively to meet its 20 percent Reserve Margin commitment to provide its customers reliable, cost-effective power. No conservation measures or renewable resources exist in this time frame to replace or mitigate this need. NRG and Calpine do not dispute the Company's reliability need for generation capacity prior to 2018, rather, they argue the Company should have selected their generation capacity proposals, rather than the Suwannee Simple Cycle Project, to meet the Company's need.

NRG and Calpine do not challenge the cost-effectiveness of the Hines Chillers Power Uprate Project to meet DEF's reliability need in the summer of 2017. No NRG or Calpine witness directly challenges DEF's testimony that the Hines Chillers Power Uprate Project is a cost-effective generation capacity resource for DEF's customers.

NRG witnesses Mr. Pollock and Mr. Dauer claim the NRG plant acquisition proposal – Acquisition 1 – that NRG submitted in response to DEF's request for proposals to meet DEF's need prior to 2018 is more cost effective than the Suwannee Simple Cycle Project based on DEF's <u>initial</u> economic evaluation. NRG ignores the results of DEF's <u>continued</u> quantitative and qualitative evaluation of that proposal that demonstrates the NRG plant acquisition proposal is not more cost effective than the Company's self-build generation projects --- even though Mr. Pollock concedes that DEF must consider quantitative and qualitative factors and should not base its decision on the results of an initial economic analysis. Mr. Pollock and Mr. Dauer ignore the results of DEF's complete evaluation of NRG's proposal because they know the firm gas transportation requirements that DEF requires to rely on the NRG plant as a firm resource to meet DEF's load-serving obligation renders the NRG acquisition proposal uneconomic. Mr. Dauer's claimed ability to operate the NRG plant on non-firm and "spot" market gas transportation arrangements in the past as an Independent Power Producer is not a substitute for DEF's obligations to provide firm power to customers at all times. Further, no NRG witness disputes the fact that the NRG Acquisition 1 proposal failed the FERC Competitive Analysis Screen rendering FERC approval of the NRG plant acquisition unlikely without substantial mitigation. For all these reasons, the Suwannee Simple Cycle Project remains a superior generation capacity resource to the NRG plant acquisition proposal that NRG continues to advance in their testimony to meet DEF's need prior to 2018.

Calpine does not rely on its initial plant acquisition or power purchase agreement ("PPA") proposal in the direct testimony of its witnesses, rather, Calpine relies on the last of its final and best offers that Calpine submitted to DEF after DEF filed its Petition in this Docket. Calpine's final and best offers moved closer to the cost effectiveness of the Suwannee Simple Cycle Project, but they still were not more cost effective than the Company's self-build generation projects to meet DEF's need prior to 2018. Calpine's primary expert witness Mr. Hibbard disputes this determination, but he fails to include all the costs associated with Calpine's final and best offer in his evaluation. To illustrate, he ignores additional transmission wheeling charges that either he or Calpine witness Mr. Simpson acknowledge exist because of the Calpine final and best offer. Mr. Hibbard also ignores qualitative risks associated with Calpine's final and best offer that present additional cost risk to DEF's customers. When all costs are included, and the qualitative cost risks accounted for in the evaluation, the Calpine final and best offer is not a superior generation capacity resource to the Company's self-build generation projects to meet DEF's need prior to 2018.

Calpine's witness Mr. Hibbard also criticizes DEF's evaluation methodology. However, he deliberately ignores or does not understand DEF's evaluation models and tools, criticizes DEF for not employing production cost economic dispatch models that DEF in fact employed, and urges the Commission instead to use his results from a simplistic screening tool for "like type" resources to evaluate different types of resources without understanding the costs and benefits of the dispatch of the resources on DEF's system. His "evaluation" is not a detailed economic analysis of the proposals or a fair and accurate criticism of DEF's detailed evaluation of the alternative generation capacity resource options to meet DEF's reliability need prior to 2018. DEF's detailed evaluation -- which includes an analysis of the economic dispatch of the alternative resources on DEF's system using the very model Mr. Hibbard said DEF should use --- demonstrates that DEF has a need for peaking generation capacity commencing in the summer of 2016 and that the Suwannee Simple Cycle Project is the most cost effective generation capacity resource to meet that need. Even the simplistic screening tool Mr. Hibbard used in his "evaluation" demonstrates that, if peaking generation capacity is needed --- which is the case beginning in the summer of 2016 --- the Suwannee Simple Cycle Project is more cost-effective than the Calpine plant under any Calpine proposal that DEF has received to meet DEF's need.

As a result, the Company decided that, based on the FERC market screen results and the results of its own detailed economic and qualitative analyses, the potential plant acquisitions under the Calpine and NRG initial or final and best offer proposals are not cost effective for the Company's customers. The Company determined that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are more cost-effective, on a quantitative and qualitative basis, than any of the alternative supply-side generation proposals. DEF requests Commission approval of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation capacity resources to meet DEF's need for generation capacity prior to 2018.

Q. Do you have any exhibits to your rebuttal testimony?

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

- Exhibit No. ___ (BMHB-12), a composite exhibit of the written communications between DEF and NRG between late May 2014 and early July 2014;
- Exhibit No. ___ (BMHB-13), a composite exhibit of the written communications between DEF and Calpine between late May 2014 and early July 2014;
- Exhibit No. ___ (BMHB-14), NRG's final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-15), DEF's evaluation of NRG's final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-16), Calpine's June 16, 2014 final and best offer to sell its plant to DEF;
- Exhibit No. ___(BMHB-17), Calpine's July 3, 2014 final and best offer to sell its plant to DEF;

- Exhibit No. ___ (BMHB-18), DEF's evaluation of Calpine's July 3, 2014 final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-19), DEF's summary of similar capital projects to the Suwannee Simple Cycle Project; and
- Exhibit No. ___ (BMHB-20), DEF's load forecasts.

These exhibits were prepared by the Company at my direction and under my control and they are true and correct.

III. THE CALPINE AND NRG CONTINUING PROPOSALS AND FINAL DEF EVALUATION OF THEIR PROPOSALS TO DETERMINE THE MOST COST EFFECTIVE GENERATION ALTERNATIVE TO MEET DEF'S NEED PRIOR TO 2018.

A. NRG AND CALPINE INITIAL GENERATION CAPACITY PROPOSALS.

Q. Did Calpine and NRG submit proposals to meet DEF's need prior to 2018?

A. Yes. As I explained in my direct testimony and as Calpine witness Mr. Thornton correctly notes in his direct testimony, DEF originally issued a solicitation for PPA proposals to meet its need for generation capacity in the 2016-2019 time frame in mid-September 2012. (Borsch Direct Testimony ("Test."), pp. 32-33; Thornton Direct Test., p. 6, lines 4-7). Both Calpine and NRG submitted PPA proposals in response to this solicitation. DEF selected both the Calpine and the NRG PPA proposals for further negotiation, but did not complete any agreement on PPA terms with either NRG or Calpine in the first quarter of 2013. The primary reason DEF suspended the negotiations for a PPA with NRG and Calpine is that DEF's need for generation capacity was changing in this time period. (Borsch Direct Test., pp. 32-33).

DEF decided to retire its Crystal River Unit 3 ("CR3") nuclear power plant in February 2013. In 2013, the Company also was evaluating the retirement of its Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") coal-fired steam generation units as early as 2015 as a result of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") Clean Air Act regulations. These impacts are discussed in more detail in my direct testimony (Borsch Direct Test., pp. 7-10), but as a result of the CR3 retirement and the potential CR1 and CR2 retirements, as well as DEF's projected load growth, DEF identified a need up to 1,150 MegaWatt ("MW") prior to 2018. This potential need prior to 2018 was identified in the Company's Revised and Restated Settlement Agreement ("2013 Settlement Agreement") approved by the Florida Public Service Commission ("FPSC" or the "Commission") in Order No. PSC-13-0598-FOF-EI. (Borsch Direct Test., p. 11).

DEF determined that DEF could reduce this need prior to 2018 by completing projects at CR1 and CR2 and employing site emission averaging at the Crystal River Energy Complex ("CREC") to comply with MATS and extend the operation of CR1 and CR2 to 2018. This plan was presented as a modification to the Company's Integrated Clean Air Compliance Plan to the Commission in December 2013 and approved by the Commission in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014). (Borsch Direct Test., pp. 8-9). As a result of this plan for the continued operation of CR1 and CR2 beyond 2016, the Company reduced its generation capacity need prior to 2018 from 1,150MW to about 470MW. (Borsch Direct Test., p. 11, lines 14-23).

Q. What happened after DEF reduced its generation capacity needs prior to 2018 with its MATS compliance plan for the continued operation of CR1 and CR2 beyond 2016?

A. In September 2013 DEF requested the respondents to DEF's earlier PPA solicitation in 2012 to submit revised proposals to DEF to meet its revised generation capacity need prior to 2018. NRG and Calpine, among others, submitted revised generation capacity proposals to meet DEF's need prior to 2018 in the fall of 2013. These supply-side proposals are described in my direct testimony. (Borsch Direct Test., p. 33, lines 19-23, p. 34, lines 1-3 and Exhibit No. ___ (BMHB-7)).

DEF also was developing generation resource options in its IRP process to meet its need prior to 2018. This process and the selection of the Company's Suwannee Simple Cycle Project, and ultimately too the selection of the Hines Chillers Power Uprate Project, to meet DEF's need prior to 2018 are described in detail in my direct testimony. (Borsch Direct Test., pp. 7-27). DEF planned to evaluate the revised bid proposals in 2013 against its Suwannee Simple Cycle Project, and later included the Hines Chillers Power

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Uprate Project, to determine the most cost effective alternative to meet its need prior to 2018.

Q. What were the NRG and Calpine generation capacity proposals to meet DEF's need prior to 2018?

A. NRG made two proposals to DEF to meet DEF's generation capacity needs prior to 2018. One NRG proposal [redacted] and the second was an acquisition proposal or an offer to sell the NRG three combustion turbine ("CT"), 471MW plant to DEF. This is the "Acquisition 1" proposal that NRG witness Mr. Pollock recommends as an alternative to DEF's self-build generation projects in his direct testimony. Both NRG proposals are identified in Exhibit No. ____ (BMHB-7) and Exhibit No. ___ (BMHB-8) to my direct testimony.

Calpine also submitted [redacted] and an acquisition proposal to DEF to meet DEF's need for generation capacity prior to 2018. Calpine's separate acquisition proposal was an offer to sell its 594MW combined cycle power plant to DEF. Calpine's PPA and acquisition proposals are also identified in Exhibit No. ____ (BMHB-7) and Exhibit No. ___ (BMHB-8) to my direct testimony.

These NRG and Calpine proposals were evaluated in DEF's generation resource options assessment that is described in detail in my direct testimony and exhibits in this Docket. As I explain there, based on that assessment, including all quantitative and qualitative costs and risks, the Company determined that the most cost effective generation to meet its need prior to 2018 was the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. (Borsch Direct Test., pp. 32-49, Exhibits Nos. ___ (BMHB-7) to ____ (BMHB-11)).

Q. Were NRG and Calpine notified by the Company that their proposals were not the most cost effective generation alternative to meet DEF's need prior to 2018 before the Company filed its Petition and direct testimony in this Docket?

A. Yes. Both Calpine and NRG were notified in February 2014 that their PPA proposals were not the most cost effective generation resource option to meet DEF's generation capacity need prior to 2018. In February, DEF also notified both NRG and Calpine of the results of the detailed economic analysis with respect to their acquisition proposals.

In particular, DEF informed both NRG and Calpine about the qualitative factors and costs that were not fully developed in the Company's detailed economic analysis that are represented by the "bars" in the cost sensitivities associated with their proposals in Exhibit No. ___ (BMHB-9) to my direct testimony -- such as, for example, the fuel arrangements for the NRG plant and the transmission constraints associated with the delivery of the Calpine plant's full capacity to DEF. DEF also informed NRG and Calpine about the potential FERC Competitive Analysis Screen issues associated with their acquisitions. DEF told NRG and Calpine that DEF had retained Julie Solomon with Navigant Consulting, Inc. to address the FERC Competitive Analysis Screen for both the NRG and Calpine acquisition proposals. These issues associated with the NRG and Calpine acquisition proposals are discussed in my direct testimony. (Borsch Direct Test., pp. 40-43).

B. NRG AND CALPINE CONTINUING DISCUSSIONS WITH DEF ABOUT THEIR PROPOSALS TO MEET DEF'S NEED PRIOR TO 2018.

Q. What happened after DEF notified NRG and Calpine in February 2014 of these results of DEF's evaluation of their proposals?

A. DEF met with NRG and Calpine by phone or in person to discuss the factors and costs associated with their acquisition proposals that were not fully developed in their proposals that presented quantitative or qualitative risk to the Company if their acquisition proposals were selected to meet DEF's generation capacity need prior to 2018. For example, DEF questioned NRG about firm gas transportation issues associated with the NRG acquisition proposal. DEF also met with Calpine in mid-February 2014 to discuss the firm transmission constraints associated with the Calpine acquisition. DEF further informed both NRG and Calpine of the results of Ms. Solomon's FERC Competitive Analysis Screen that showed both the NRG and Calpine acquisition proposals failing the Screen. DEF later brought Ms. Solomon to Florida to discuss the FERC Competitive Analysis Screen and the results of her Screen analyses for the NRG and Calpine acquisitions with the Office of Public Counsel on May 12, 2014. One purpose of this meeting was to explain the results of DEF's evaluation of the most cost effective generation alternative to meet its need prior to 2018. Other parties attended this meeting, including Calpine's attorney.

The purpose of these discussions between the Company and NRG and Calpine was to focus on the quantitative and qualitative factors in their acquisition proposals that were impediments to the selection of their proposals to meet DEF's need prior to 2018 and to discuss what could be done by NRG and Calpine, if anything, to overcome them. DEF made clear to NRG and Calpine that, based on the quantitative and qualitative risks associated with their acquisition proposals that were identified in DEF's evaluation, their proposals were not more cost effective than the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project.

Q. Were any revisions made by either NRG or Calpine to their proposals during or following these discussions with the Company?

A. No. DEF received no revisions from either NRG or Calpine to their proposals to meet DEF's need prior to 2018 to address the impediments that DEF identified with the selection of their proposals. DEF formally announced its selection of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternative to meet its need prior to 2018 on May 13, 2014. Both NRG and Calpine were informed of this decision.

Q. Were there any revised proposals from NRG or Calpine after DEF's announcement?

A. No, not before DEF filed its Petition and Direct Testimony and Exhibits in this Docket. NRG did not submit any proposal to DEF during this time period from February 2014 to the end of May 2014. Calpine did submit an acquisition proposal to DEF on April 30, 2014, as Mr. Thornton states in his direct testimony (Thornton Direct Test., p. 7, lines 14-16), but this was the exact same acquisition proposal that Calpine had previously submitted following DEF's September 2013 solicitation and that DEF evaluated in its generation resource evaluation to determine the most cost effective generation alternative to meet its need prior to 2018. Calpine did not submit a revised PPA or acquisition proposal to DEF before DEF filed its Petition and Direct Testimony and Exhibits in this Docket on May 27, 2014.

C. FINAL AND BEST OFFERS.

Q. Did DEF end its discussions with NRG and Calpine about their proposals after DEF filed its Petition in this Docket?

A. No. DEF did not stop taking calls from NRG and Calpine and DEF did not stop communicating with them about their proposals after DEF filed its Petition in this Docket, even though DEF had no obligation to continue such discussions with them. DEF already had informed them about the impediments to selecting their proposals and, although DEF received no response to these impediments prior to DEF filing its Petition in this Docket, DEF was willing to continue the discussions with them because DEF was genuinely interested in purchasing one of their plants if the purchase made sense and offered superior customer value to the Company's self-build generation options. DEF informed both NRG and Calpine of the continuing discussions with DEF and both parties. DEF encouraged both NRG and Calpine to give DEF a final and best offer for the acquisition of their plants with a plan to deal with any FERC Competitive Analysis Screen issue associated with the plant acquisition.

Q. Was there more than one discussion with NRG and Calpine about a final and best offer to DEF?

A. Yes. From late May to early July 2014, DEF had numerous communications and calls with NRG and Calpine regarding their plant acquisition proposals in an attempt to obtain a final and best offer from NRG and Calpine. DEF also met with NRG and Calpine representatives in person, bringing together their lawyers and technical experts with DEF's lawyers and DEF's resource planning and regulatory accounting experts, to determine if there was a way to overcome the economic impediments and qualitative risks associated with their plant acquisitions by DEF structured in a way to get around the FERC market screen failures that DEF's expert had identified with their acquisitions.

Q. Please describe your discussions with NRG.

A. DEF met with NRG on May 27, 2014 and on June 12, 2014. During these meetings DEF discussed the details of its evaluation of NRG's acquisition proposal and the economic, qualitative, and FERC market screen impediments to DEF selecting this acquisition over its self-build generation options. DEF provided the details of this evaluation to NRG and DEF provided NRG with DEF's evaluation of NRG suggested proposals to structure the NRG plant acquisition in a way that evaded any FERC market screen failures while holding DEF and its customers harmless from any costs that would occur if FERC approval was not obtained or if FERC required mitigation to eliminate the market screen failures that DEF's expert identified with the NRG acquisition. DEF continued correspondence and communications with NRG about the structure of the NRG plant acquisition between and after these meeting dates into early July 2014. Copies of the written communications between DEF and NRG during this period are included as a composite Exhibit No. ____ (BMHB-12) to my rebuttal testimony.

Q. Were there similar discussions between DEF and Calpine?

A. Yes. DEF continued its communications with Calpine to obtain a final and best plant acquisition offer from Calpine. DEF met with Calpine on June 2, 2014 and had follow up conference calls with Calpine on June 9, June 11, and July 1, 2014. DEF provided Calpine with the details of DEF's evaluation of Calpine's acquisition proposal and the economic, qualitative, and FERC market screen impediments to DEF selecting this acquisition over its self-build generation options. Following each of these meetings DEF analyzed Calpine's alternative proposals to overcome the economic and qualitative impediments to the acquisition of Calpine's plant. DEF also analyzed and provided Calpine its analysis of Calpine's suggested proposals to structure the Calpine plant acquisition in a way that evaded the FERC market screen failures while ensuring that DEF's customers did not incur any costs if FERC approval was not obtained or if FERC required mitigation to eliminate the market screen failures that DEF's expert had identified with the Calpine acquisition. DEF continued correspondence and communications with Calpine about the structure of the Calpine plant acquisition between and after these meeting dates into early July 2014. Copies of the written communications between DEF and Calpine during this period are included as a composite Exhibit No. ____ (BMHB-13) to my rebuttal testimony.

Q. The structure of these proposals sounds complicated, why were the proposals structured this way?

A. They were complicated proposals. The only proposals to meet DEF's need prior to 2018 that were potentially cost effective for DEF's customers were the proposed acquisitions. These acquisitions were the only long-term proposals ever submitted by NRG or Calpine to meet DEF's need prior to 2018 and they were more economic than the PPA proposals that NRG and Calpine submitted. If DEF was going to do a deal with either NRG or Calpine for the benefit of DEF's customers that deal would be for the acquisition of either the NRG plant or the Calpine plant.

The straight-forward acquisition of the plants, which is what both NRG and Calpine originally proposed, however, failed the FERC Competitive Analysis Screen. FERC approval of the NRG and/or Calpine plant acquisitions was required. The FERC Competitive Analysis Screen failures for both acquisitions meant that DEF likely could not obtain FERC approval to acquire the plants without undertaking substantial transmission mitigation to expand the DEF market and eliminate the screen failures. These FERC Competitive Analysis Screen failures for both the NRG and the Calpine straight-forward acquisition proposals and the likely substantial transmission mitigation required to eliminate the screen failures are described in detail in the direct testimony and exhibits of Julie Solomon in this Docket. No NRG or Calpine witness disputes Ms. Solomon's direct testimony and analysis that the straight-forward acquisitions of the NRG and Calpine plants fail the FERC Competitive Analysis Screen and that substantial transmission mitigation is likely necessary to eliminate the screen failures. In fact, Calpine witness Dr. Hunger expressly agrees with her testimony and analysis of the FERC Competitive Analysis Screen for the straight-forward DEF acquisitions of the NRG and Calpine plants. (Hunger Direct Test., p. 20, lines 1-13). This risk of FERC disapproval, or the likelihood of FERC approval only if substantial mitigation costs were incurred, prevented DEF from pursuing a straight-forward, economic plant acquisition proposal from NRG or Calpine.

Q. Was this FERC problem a primary reason for the complicated structure of the NRG and Calpine proposals?

A. Yes. One of the primary focuses of the continued discussions with both NRG and Calpine to obtain a best and final acquisition offer from them was how to structure the deal to get DEF the value of the acquisition of the plants without running afoul of the FERC Competitive Analysis Screen. Both NRG and Calpine asserted that all DEF had to do was enter into a PPA with an acquisition option or requirement to avoid the FERC Competitive Analysis Screen and, therefore, obtain FERC approval. NRG and Calpine disagreed and continue to disagree on the length of that PPA, and how soon DEF could seek FERC approval of the acquisition in the PPA in order to get out of the PPA if FERC did not approve it or if FERC required mitigation. This is evident in the direct testimony of NRG witness Dr. Morris and Calpine witness Dr. Hunger in this Docket. (Hunger Direct Test., p. 4, lines 8-10, p. 17, lines 21-22; Morris Direct Test., p. 12, lines 20-21, p. 13, lines 1-10, p. 18, lines 18-21).

DEF's position then and now is that if NRG and Calpine are so sure that FERC would approve their proposed PPA structures to consummate DEF's acquisition of their plants as soon as possible, then, NRG and Calpine should bear all risks associated with obtaining or failing to obtain that approval from FERC. This included, among other costs, (i) all the sunk costs and the costs associated with deferring the Suwannee Simple Cycle Power Plant at least a year to attempt to obtain FERC approval of the acquisition; (ii) the additional, extra PPA costs associated with the PPA term until the acquisition could be

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consummated; and (iii) all costs, including legal and expert fees, at FERC to attempt to obtain FERC approval of the PPA with the acquisition option. In other words, DEF expected NRG and Calpine to take all the risk --- not DEF's customers --- that FERC would not approve their proposed PPA structure with the plant acquisition to get DEF the value of the acquisition as soon as possible without substantial mitigation. Structuring the deal to accomplish this objective was complicated.

1. NRG'S FINAL AND BEST OFFER.

Q. Did NRG make a final and best offer to DEF?

A. Yes. NRG submitted a final and best offer to DEF on June 18, 2014. NRG's final and best offer was intended, we believe, to address DEF's quantitative and qualitative concerns with NRG's original acquisition proposal including the FERC Competitive Analysis Screen failure. NRG's final and best offer is included as Exhibit No. ___ (BMHB-14) to my rebuttal testimony.

Q. Were DEF's concerns addressed in NRG's final and best offer?

A. No. NRG's final and best offer was at least [redacted] negative on a Cumulative Present Value Revenue Requirements ("CPVRR") basis compared to the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project. NRG proposed [redacted]

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[redacted]. DEF's response to NRG and evaluation of NRG's final and best offer is included in Exhibit No. ___ (BMHB-15) to my rebuttal testimony.

Q. Does NRG refer to its final and best offer to DEF in its direct testimony?

A. No. No NRG witness in this Docket argues or recommends that DEF should have selected the NRG final and best offer as the most cost effective alternative to meet DEF's generation capacity need prior to 2018.

The only NRG witness is a witness who challenges DEF's firm gas transportation requirements for the NRG plant if DEF acquired the plant. (See Dauer Direct. Test., p.3). He refers only to the NRG initial acquisition proposal --- Acquisition 1 --- to meet DEF's 2018 generation capacity need. (Id.). He does not mention or describe NRG's final and best offer to DEF.

NRG witness Mr. Pollock is an expert retained by NRG to testify in this Docket and NRG witness Mr. Pollock recommends the initial NRG plant acquisition proposal --- Acquisition 1 --- that NRG made to DEF to meet DEF's 2018 need. (Pollock Direct Test., pp. 6-7, 28). NRG witness Mr. Pollock does not even mention much less describe the NRG final and best offer.

The NRG plant acquisition that NRG witness Mr. Pollock recommends is the plant acquisition that was not more cost effective on a quantitative and qualitative basis than the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project, for the reasons provided in my direct testimony, and that failed the FERC Competitive Analysis Screen for the reasons provided in the direct testimony of Julie Solomon in this Docket. (Borsch Direct Test., p. 40-48; Solomon Direct Test., p.20, lines 13-23, p. 21, lines 1-4, pp. 22-23).

Q. Does NRG witness Dr. Morris disagree with the FERC Competitive Analysis Screen analysis performed for the NRG Acquisition 1 proposal recommended by Mr. Pollock?

A. No. NRG witness Dr. Morris does not even mention the NRG Acquisition 1 proposal at all in his direct testimony --- despite the fact that NRG witness Mr. Pollock actually recommends the Acquisition 1 proposal to DEF and the Commission as the most cost effective alternative to meet DEF's need prior to 2018. (Morris Direct Test., p. 5, lines 15-20, pp. 6-6; p. 12, lines 20-21, p. 13, lines 1-10; Pollock Direct Test., p. 6, lines 18-21). No NRG witness testifies that the NRG Acquisition 1 proposal passes the FERC Competitive Analysis Screen or that it would otherwise be approved by FERC without mitigation. NRG, then, does not dispute the testimony of Ms. Solomon that the NRG Acquisition 1 proposal fails the FERC Competitive Analysis Screen and that FERC likely would not approve the acquisition without substantial mitigation.

Q. Does Dr. Morris address the NRG final and best offer in his direct testimony?

A. No. Dr. Morris does not refer to or describe NRG's final and best offer. In fact, Dr. Morris does not refer to any actual NRG contract proposal for the acquisition of the NRG plant by DEF at all in his direct testimony.

Dr. Morris discusses hypothetical PPAs of various terms, from five to ten years, with or without tolling arrangements, with the option for DEF to "purchase the [NRG] facility at <u>some</u> date under <u>some</u> <u>set of terms</u>." (Morris

Direct, Test. p. 12, lines 20-21, p. 13, lines 1-10, p. 18, lines 14-21) (emphasis added). Dr. Morris concludes that these hypothetical PPAs with an acquisition option would pass muster at FERC because they would be -- if they existed -- PPAs under which DEF had the rights to the NRG plant capacity for some time and, therefore, would similarly control that output at the time of the acquisition "several" years later, thus, demonstrating no change of control triggering a FERC market screen analysis or screen failure. (Morris Direct Test., p. 14, lines 5-8). That may or may not be true, Dr. Morris is correct that Ms. Solomon did not perform that analysis (Morris Direct Test., p. 11, lines 3-6), because there is nothing to analyze. There simply are no terms for DEF to evaluate to determine the economic value to customers.

Remarkably, Dr. Morris fails to address the actual facts of this case, involving the NRG initial Acquisition 1 proposal and the NRG final and best offer attempt to address the quantitative and qualitative impediments to the cost-effectiveness of that proposal and the NRG proposed FERC market screen "work around" to sell the plant to DEF. Dr. Morris chooses to ignore NRG's final and best offer.

Dr. Morris also claims that Ms. Solomon and DEF failed to consider a case before FERC where, if the NRG Acquisition 1 proposal was not accepted by DEF --- which is the case because it is not cost effective --- NRG would either exit the DEF Balancing Area Authority ("BAA") by physically moving its CT plant to another location outside the DEF BAA or "moving out" its plant by selling the capacity or plant to another utility outside the DEF BAA. (Morris

Direct Test., p. 11, lines 7-10; p. 14, lines 15-21, pp. 15-16). Dr. Morris is correct that DEF and Ms. Solomon did not consider these "cases" because, again, they have nothing to do with the actual facts in this case.

NRG never told DEF that it was actually going to move its CTs outside the DEF BAA or that NRG had a contract to sell its plant capacity or its entire plant to a utility outside the DEF BAA if DEF did not accept its Acquisition 1 proposal or its final and best offer. See Exhibit No. ___ (BMHB-12) to my rebuttal testimony. NRG's final and best offer to DEF contains no such factual representations. See Exhibit No. ____ (BMHB-14). No NRG witness has testified in this Docket that NRG will in fact move its CTs outside the DEF BAA or that NRG in fact has an alternative contract to sell its plant capacity or its entire plant to a utility outside the DEF BAA if DEF does not accept its Acquisition 1 proposal. Simply put, DEF could not and did not evaluate what factually never existed. Nonetheless, Ms. Solomon addresses these arguments and their impact to FERC issues in her rebuttal testimony.

2. CALPINE'S FINAL AND BEST OFFER.

Q. Did Calpine make a final and best offer to DEF?

A. Calpine made a couple of final and best offers to DEF. The first Calpine final and best offer was presented to DEF on June 16, 2014. Calpine's June 16, 2014 final and best offer is included as Exhibit No. ___ (BMHB-16) to my rebuttal testimony. The last one is the July 3, 2014 proposal that witness Mr. Thornton identifies and generally describes in his direct testimony. (Thornton

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Direct Test., pp. 8-9). Calpine's July 3rd final and best offer is included as Exhibit No. ___ (BMHB-17) to my rebuttal testimony.

Q. What was the first final and best offer that Calpine made to DEF?

A. Calpine proposed [redacted]

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[redacted] See Exhibit No. ___ (BMHB-16) to my rebuttal testimony.

Q. What was DEF's response to the Calpine June 16th offer?

A. DEF could not accept this offer because it did not "close the gap" between the [redacted]

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[redacted] DEF explained this to Calpine in a June 26, 2014 letter that is included in Exhibit No. ___ (BMHB-13) to my rebuttal testimony.

Q. What was Calpine's response to DEF's concerns in DEF's June 26, 2014 letter to Calpine?

A. Calpine's response was to make its July 3rd final and best offer to DEF. Calpine witness Mr. Thornton correctly describes this July 3rd offer in his direct testimony as a five-year PPA for 515MW of capacity and energy with a guaranteed heat rate and plant availability. Calpine lowered the capacity payments during the PPA. (Thornton Direct Test., p. 8, lines 2-15; Exhibit No. ___ (BMHB-17) to my rebuttal testimony). [redacted] provided DEF the option to purchase the plant for [redacted] "subject to certain adjustments the terms of which would be negotiated by Calpine" and DEF. (Thornton Direct Test., p. 8, lines 15-19). Calpine further provided for the first time terms that addressed the risk that FERC might not approve the Calpine

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PPA-acquisition proposal or that FERC might approve it only with mitigation. All other terms of the Calpine July 3rd final and best offer remained the same as the June 16th Calpine offer. See Exhibit No. ___ (BMHB-17) to my rebuttal testimony. In this final and best offer Calpine attempted to address DEF's concerns with its initial plant acquisition proposal and its June 16th final and best offer and to "close the gap" between the cost effectiveness of the Calpine plant acquisition and the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's need prior to 2018.

Q. Was the Calpine July 3rd final and best offer more cost effective for DEF's customers than the Company's self-build generation projects?

A. No. On a CPVRR basis, accounting for all the costs to DEF of the Calpine July 3rd final and best offer, the Calpine July 3rd offer is still [redacted] less cost effective in a FERC no mitigation scenario, [redacted] less cost effective in a FERC mitigation scenario where DEF has to default to a delayed DEF self-build generation plan, and [redacted] less cost effective if DEF were to accept the full five years of the PPA with no acquisition. Calpine moved closer to the cost-effectiveness of DEF's self-build generation resources to meet DEF's need prior to 2018, but Calpine did not fully close that gap, thus, the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are still the most cost effective generation capacity resources to meet DEF's need prior to 2018. Please see DEF's evaluation of Calpine's July

3rd final and best offer attached as Exhibit No. ___ (BMHB-18) to my rebuttal testimony.

Q. Calpine witness Mr. Hibbard claims that the Calpine July 3rd final and best offer not only closed the gap but that it is actually $133 million more cost-effective than the Company's self-build generation projects to meet DEF's need prior to 2018. Do you agree with Mr. Hibbard?

A. No. Mr. Hibbard is wrong. First, he fails to include transmission costs to deliver the Calpine plant capacity across TEC's system to DEF that he and Calpine witness Mr. Simpson acknowledge must exist. Second, he fails to include costs that necessarily result from the deferral of the Calpine plant acquisition to a later point in time. Third, he makes an adjustment to DEF's planned firm gas transportation to incorporate the Calpine plant into DEF's generation system that fails to recognize that DEF is operating a generation system to meet its statutory obligation to serve its customers --- not a single combined cycle plant operated on a merchant basis like Calpine --- and actually results in higher future firm gas transportation costs to incorporate that plant into DEF's generation system. Fourth, he fails to include costs that Calpine itself admits exist if DEF defers its self-build generation project in an attempt to obtain FERC approval of the Calpine PPA-acquisition proposal. Finally, Mr. Hibbard ignores qualitative risks that add cost to the Calpine proposed PPA-acquisition, including the assumption that there is no FERC approval or mitigation risk, even though his own client accounted for that risk in Calpine's July 3rd proposal, albeit in a manner that did not fully address that risk in a cost effective manner. For all these reasons, Mr. Hibbard is wrong and the Calpine July 3rd final and best offer still is not a cost effective option, considering all quantitative and qualitative factors, to meet DEF's need prior to 2018. See Exhibit No. ___ (BMHB-18) to my rebuttal testimony.

Q. Can you explain the transmission costs that Mr. Hibbard does not account for in his analysis of the CPVRR impact of the Calpine July 3rd offer?

A. Yes. Calpine and Mr. Hibbard now acknowledge there are $150 million in transmission costs to provide a direct connection from the Calpine plant to DEF's system to ensure the firm transmission of the full plant capacity to DEF (Thornton Direct Test., p. 14, lines 9-12; Hibbard Direct Test., pp. 25-26). However, the $150 million in transmission costs for the direct connection of the Calpine plant to DEF's system are <u>future</u> costs since even Calpine acknowledges DEF will not want to incur these costs until FERC approves the ultimate acquisition of the Calpine plant (Thornton Direct Test., p. 10, Lines 7-11), and Calpine admits it will take at least three years to construct this necessary transmission to ensure DEF can obtain the Calpine plant capacity "year-round on a long-term basis." (Thornton Direct Test., p. 10, lines 4-7; Simpson Direct Test., p. 14, line 13). In the meantime, under the PPA in the July 3rd Calpine offer, under which Calpine requires DEF to pay for the full

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plant capacity year-round, DEF does not have firm transmission rights to obtain the full plant capacity across TEC's system and onto DEF's system.

Mr. Hibbard admits --- contrary to Mr. Simpson's testimony --- that only 249MW of the Calpine plant capacity can be supplied on a firm basis under the PPA prior to the new $150 million transmission infrastructure. (Hibbard Direct Test., p. 13, lines 21-23). While Mr. Simpson takes the position that the Calpine plant can firmly deliver DEF more than 249MW of plant capacity even before the new transmission infrastructure is constructed with the use of operating procedures and re-dispatch of generation resources by both DEF and TEC, he at least admits that "additional transmission service will need to be purchased from TEC for the delivery of additional energy and capacity" from Calpine's plant to DEF. (Simpson Direct Test., p. 8, lines 12-14). Mr. Hibbard does not include the costs for this additional transmission service to deliver the full plant capacity to DEF under the PPA in the Calpine July 3rd offer in his CPVRR adjustments. DEF, in its evaluation of the Calpine offer, attempted to address these issues by modeling a scenario in which the available transmission capacity was limited to 249MW during four peak months of the year and the full 515MW was available during the remaining eight months, shaping the expected transmission charges owed to TEC accordingly. The cost of this transmission service over the term of the PPA in the July 3rd offer has a negative CPVRR impact of [redacted] for the Calpine PPA-acquisition proposal. Mr. Hibbard ignores these costs in his adjustments to the CPVRR evaluation in his direct testimony.

Q. Do you agree with Mr. Simpson that DEF can receive the full capacity of the Calpine plant and that the plant is not limited to delivering only 249MW of plant capacity to DEF before the additional transmission infrastructure to directly connect the plant to DEF is built?

A. No. On this point Mr. Hibbard is correct, under the proposed PPA before the plant acquisition and the transmission infrastructure is constructed, Calpine is limited to providing DEF 249MW of plant capacity on a firm basis. Mr. Simpson himself concedes that this limit applies during peak load hours of the year --- which of course is when DEF will actually need the full plant capacity --- unless operating procedures are employed or DEF or TEC or both re-dispatch their generation resources to avoid overloads and other transmission constraints he admits exist on the grid. (Simpson Direct Test., pp. 11-12). Mr. Scott addresses this argument in his rebuttal testimony from the transmission perspective, but from the resource planning perspective, Mr. Simpson's suggested ways around the transmission constraints at peak hours to deliver the full plant 515MW capacity to DEF do not turn non-firm transmission capacity into firm transmission capacity. I am responsible for ensuring that DEF meets its statutory obligation to serve and, during peak load hours, the Calpine plant under the July 3rd Calpine offer is only a 249MW firm generation resource.

No utility with an obligation to serve will rely on transmission operating procedures or the re-dispatch of other generation resources by another utility in an attempt to avoid or limit transmission constraints as firm transmission generation. That simply is not standard utility practice. Indeed, by re-dispatching generation resources Mr. Simpson means that the utilities are deciding to change the economic dispatch of generation resources just to avoid transmission constraints. This might be a temporary measure by a utility managing its own generation resources to mitigate a limited transmission constraint, but re-dispatching otherwise economically dispatched generation to avoid transmission constraints is obviously not the most cost effective allocation of generation resources. Also the suggestion that re-dispatch may be utilized during peak hours is only feasible if the utilities have sufficient generation flexibility at peak to de-rate selected generation units while still being able to meet peak load. Neither Mr. Simpson nor Mr. Hibbard account for the cost of this inefficient allocation of generation resources in their direct testimony despite advocating this approach and Calpine nowhere in its July 3rd proposal offered to pay DEF and its customers for this cost to accommodate the transmission of Calpine's plant capacity to DEF. As discussed above, DEF in its evaluation modeled this constraint by shaping the available transmission in peak and off-peak months.

In addition, neither Calpine, Mr. Hibbard, or Mr. Simpson account for the cost of the uneconomic dispatch on TEC's system, even if TEC was inclined to agree to the uneconomic re-dispatch of its generation resources on its system to accommodate the delivery of Calpine's plant capacity across TEC's system to DEF. Surely Calpine and its witnesses do not expect DEF's

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customers and TEC's customers to assume this uneconomic re-dispatch cost to enable Calpine to deliver its full plant capacity to DEF when it is needed.

Q. What costs are associated with the plant acquisition at a later date under the July 3rd offer that Mr. Hibbard does not include in his analysis?

A. DEF included costs to account for the Calpine plant condition including necessary expected maintenance contract and other costs to align the maintenance of the Calpine plant with DEF's other combined cycle generation plants if the Calpine plant was acquired by DEF. The Calpine plant, despite Calpine's witnesses' claims about its reliable operation, is ten years old and it will be at least 15 years old at the latest time of the acquisition under the Calpine July 3rd PPA-acquisition offer. Notably, Calpine failed to guarantee upon acquisition the performance or maintenance of the Calpine plant in its July 3rd offer. DEF included direct costs of [redacted] with a CPVRR impact o[redacted]. It is unreasonable for Calpine and Mr. Hibbard to ignore any additional cost to DEF to maintain and incorporate a 15-year old plant into its system. See Exhibit No. ___ (BMHB-18).

In addition, DEF included transaction costs for the actual plant acquisition, which again, Calpine failed to include in its July 3rd offer and Mr. Hibbard failed to include in his CPVRR adjustments. Calpine must admit that there would necessarily be such transaction costs, because even Calpine explains that its offer was <u>not</u> final, but instead subject to negotiation. (Thornton Direct Test., pl. 8, lines 15-16; p. 9, lines 10-12). These costs also

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impact the economic comparison of the Calpine July 3rd offer to the Company's self-build generation projects. DEF included a [redacted] estimate for these costs. See Exhibit No. __ (BMHB-18).

Q. Why is Mr. Hibbard's firm gas transportation cost adjustment incorrect?

A. Mr. Hibbard makes a substantial [redacted] adjustment to the CPVRR economic evaluation of the Calpine July 3rd proposal based on his unwarranted and unsupported assumption that [redacted]. (Hibbard Direct Test., p. 32, lines 1-6). In other words, Mr. Hibbard says DEF should simply [redacted] Mr. Hibbard claims this is a fair allocation because DEF purchases gas on a system or fleet-wide basis, and, therefore, according to him, to level "the playing field" between DEF generation resources and third-party proposals the DEF firm gas transportation contracts should be transferable to any proposal including Calpine's proposal. (Hibbard Direct Test., pp. 30-31).

Mr. Hibbard makes an unsupported assumption that the gas transportation contracts which supply the Suwannee site can be redirected to the Calpine Osprey plant location. This is not correct. Different gas transportation contracts have different and specific delivery points and there are limits to the degree to which they can be interchangeable or redirected. Specifically, the Suwannee plant is supplied by Florida Gas Transmission ("FGT") while the Calpine Osprey plant site is supplied by Gulfstream. DEF cannot simply redirect its transportation from one pipeline network to the other and would require service on each system to supply different locational needs. Neither can DEF reasonably release its contracted FGT capacity, which is an integral part of its portfolio with delivery to multiple DEF sites, and "replace" it with the transportation contracted to the Calpine Osprey plant.

Mr. Hibbard, of course, does not work for any public utility, much less DEF, so he has no basis to testify at all to how public utilities and DEF, in particular, purchase firm gas transportation for their systems. Mr. Patton is responsible for firm gas transportation for DEF on DEF's system and provides rebuttal testimony in this Docket addressing Mr. Hibbard's erroneous assumptions. From a resource planning perspective, I know that the fact that DEF purchases firm gas transportation to serve its generation fleet on a system basis does not mean that DEF simply can transfer firm gas transportation from one generation resource to another generation resource on its system or to generation resources not on its system yet, like the Calpine plant under the PPA part of the July 3rd PPA-acquisition offer. This is not the "one-size-fits-all" simplistic view that Mr. Hibbard applies to his firm gas transportation adjustment.

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As mentioned above, there is another reason Mr. Hibbard's simplistic view is inaccurate. If DEF has reserved firm gas transportation now for its Suwannee Simple Cycle Project it does not make economic sense for DEF and its customers to give that firm gas transportation up now for the Calpine proposal or any other proposal only for DEF to have to buy back future firm gas transportation at a higher price when DEF knows its system is growing. Mr. Hibbard's firm gas transportation CPVRR adjustment fails to compensate DEF's customers for the differential cost that is lost if DEF must purchase firm gas transportation in the future at a higher cost to replace the firm gas transportation it has now but must give up to Calpine under Mr. Hibbard's simplistic view of the use of system firm gas transportation resources.

Q. Did Mr. Hibbard account for the costs associated with the extended operation of the Suwannee Steam units?

A. No. One of the benefits of the construction of the Suwannee Simple Cycle Project is that it allows for retirement of the more than 50-year old Suwannee Steam units in 2016. Both Calpine and Mr. Hibbard failed to account for the cost to extend the retirement of the Suwannee steam units from 2016 to 2018 if FERC approves the Calpine July 3rd PPA-acquisition proposal without mitigation. The Suwannee steam units are needed for transmission grid reliability in the North Florida area between 2016 and 2018 if the Suwannee Simple Cycle Project is not placed in commercial operation in 2016. DEF included these costs with a CPVRR impact of [redacted] in its analysis.

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Q. What additional costs did Mr. Hibbard fail to include for the deferral of the self-build generation projects while DEF and Calpine attempt to obtain FERC approval for the Calpine PPA-acquisition proposal?

A. As explained above, DEF announced in May 2014 that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were the most cost effective generation capacity to meet DEF's need prior to 2018. DEF filed its Petition and Direct Testimony in support of that determination and DEF necessarily is incurring costs to ensure that the Suwannee Simple Cycle Project can be completed in time to meet DEF's need in 2016 --- all before DEF received the Calpine final and best offer, which is still subject to FERC approval. There are, therefore, sunk costs associated with this Project that Calpine --- not DEF's customers --- must assume. [redacted] Mr. Hibbard fails to include this cost in his CPVRR analysis entirely.

Finally, there obviously will be costs, including legal and expert fees, associated with any attempt to obtain FERC approval of the Calpine July 3rd PPA-acquisition proposal. [redacted] See Exhibit No. ___ (BMHB-17). Mr. Hibbard never included these costs in his CPVRR analysis. DEF and its customers obviously

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should not be responsible for the costs of obtaining FERC approval for Calpine's July 3rd proposal.

Recognizing that these costs totaling at least [redacted] might be the subject of a future "negotiation" on the final purchase price, DEF did not directly include these in its CPVRR analysis, but DEF has identified them as a potential reduction in any benefit to customers if Calpine is not willing to fully net them against the purchase price.

Q: Did Calpine offer any offset to the Suwannee Project Costs?

A. Calpine offered [redacted] its July 3rd offer. (See Exhibit No. ___ (BMHB-17); Thornton Direct Test., p. 9, lines 7-9) [redacted] See Exhibit No. ___ (BMHB-18) to my rebuttal testimony. [redacted] See Exhibit No. ___(BMHB-17).

Q. Please explain the qualitative factors that add risk and cost to the Calpine July 3rd offer.

A. As I explained above, Calpine acknowledges that many of the terms and conditions of Calpine's July 3rd PPA-acquisition proposal remain to be negotiated and, in Calpine's view, are "subject to certain adjustments." (Thornton Direct Test., p. 8, lines 9-10). This includes the terms for the actual purchase price for the acquisition of the Calpine plant by DEF. (Id.). It also includes a reference to the PPA "escape clause" in the event that FERC did not approve the Calpine July 3rd PPA-acquisition offer. (Thornton Direct Test., p. 9, lines 1-13). The fact that these critical terms remain subject to negotiation and "adjustment" hardly means DEF has a deal where all costs are known and all risks have been mitigated or allocated between DEF and Calpine. There are, therefore, qualitative risks associated with the Calpine July 3rd PPA-acquisition offer that represent risk and additional cost to DEF and its customers.

Q. What do you mean by the PPA "escape" clause?

A. As I explained above, the value, if any, of the Calpine proposal to DEF's customers is the <u>immediate</u> acquisition of the Calpine plant. A PPA for the Calpine plant capacity is not economic for DEF's customers and, in fact, the longer DEF is in a PPA prior to the plant acquisition, the less economic the deal is for DEF's customers. In other words, the PPA does not add value to the acquisition transaction; it detracts from the value of the acquisition transaction.

The only reason that DEF entertained a PPA with the plant acquisition was because Calpine claimed that Calpine could structure a PPA to provide the acquisition value to DEF while at the same time passing FERC muster when the straight-forward acquisition failed the FERC Competitive Analysis Screen. DEF was willing to entertain this structure if DEF could get to the

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plant acquisition value --- if there was economic value to DEF customers to the plant acquisition in the deal --- as soon as possible by obtaining early FERC approval of the PPA-acquisition offer, and, if FERC did not approve the PPA-acquisition proposal or FERC approved it subject to required mitigation, DEF could get out of the PPA. Hence, the "escape" clause that DEF required and that Calpine finally provided in the July 3rd PPA-acquisition proposal, albeit still subject to further negotiation on the final terms. See Exhibit No. ___ (BMHB-17).

This "escape" clause provision necessarily committed DEF to a minimum two-year PPA with Calpine while DEF and Calpine sought FERC approval of the PPA-acquisition proposal and, if it was not approved or was only approved subject to required mitigation, DEF deferred the in-service of the Suwannee Simple Cycle Project to 2017. This "escape" clause detracted from the value of the Calpine July 3rd offer. In fact, the minimum two-year PPA under the "escape" clause resulted in a negative CPVRR impact of [redacted] compared to the Company's self-build generation projects. See Exhibit No. ___ (BMHB-18). Neither Calpine nor Mr. Hibbard account for this negative CPVRR impact. They both ignore it in their direct testimony.

Q: Did Calpine offer an offsetting payment in this case?

A: DEF identified, and Calpine recognized, that in the event that DEF suspended the Suwannee Project during the period of consideration by FERC, DEF would incur costs regardless of FERC's eventual ruling on the Calpine PPA-

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acquisition proposal. In the event of FERC approval, DEF and Calpine would have to negotiate, in advance, a settlement for the project costs so that they would not accrue to customers as discussed earlier. In the event that FERC does not approve the Calpine PPA-acquisition proposal, or requires mitigation, DEF would incur cost for suspending and restarting the project as well as carrying costs for the funds already committed and the costs for extended operation of the Suwannee steam units.

Calpine offered [redacted] (See Exhibit No. ___ (BMHB-17) and Thornton Direct Test., p. 9, lines 7-9). [redacted] See Exhibit No. ___ (BMHB-18) to my rebuttal testimony. [redacted] See Exhibit No. ___ (BMHB-17). Mr. Hibbard, however, failed to include [redacted] in his analysis.

Finally, [redacted] are based on DEF's ability to exercise the "escape clause" at the end of year two of the PPA (or in 2016). If the PPA were to run the full 5-year period, the alternative would be significantly worse in CPVRR impact compared to proceeding with the Suwannee Simple Cycle Project now.

Q. What does Calpine say about the FERC review of its July 3rd offer?

A. Mr. Thornton claims that Calpine addressed DEF's FERC concerns in Calpine's July 3rd offer. He refers to Dr. Hunger's direct testimony to support this assertion. (Thornton Direct Test., p. 14, lines 16-23). Dr. Hunger does claim a five-year PPA with an acquisition offer at the end of the PPA will easily obtain FERC approval, even without a FERC Competitive Screen Analysis. (Hunger Direct Test., p. 4, lines 7-10, p. 13, lines 1-7). Dr. Hunger's description of a typical five-year, long-term PPA with an acquisition option at the end likely will pass FERC muster without a FERC Competitive Analysis Screen. The problem is, the Calpine July 3rd offer is not a typical five-year PPA with an acquisition option at the end.

DEF has no intention of entering into a long-term PPA for the Calpine plant capacity with an offer to acquire the plant available at the end of that period. DEF knows that PPA is not economic for DEF's customers. The intent of the PPA, again, is to get to the plant acquisition value, if any, and to obtain that value for DEF's customers by obtaining FERC approval for the acquisition as quickly as possible. Mr. Thornton makes clear he understood this was the intent of the deal when he describes the "escape" clause as a means of protecting DEF in the event that FERC denied DEF's application "for approval of the acquisition." (Thornton Direct Test., p. 9, lines 3-6). Dr. Hunger does not specifically opine on whether FERC would or would not approve this PPA, one in which the parties specifically structured it to evade the FERC market screen issues associated with the straight-forward acquisition of the plant.

Indeed, Dr. Hunger backs off the certainty of his opinion of FERC approval of the five-year PPA with an acquisition option at the end of the term when he moves to his discussion of a situation where the FERC application would be filed as soon as the PPA is executed. In this situation, Dr. Hunger simply states that he believes there is FERC support for this type of structure. (Hunger Direct Test., p. 21, lines 8-18). This "type of structure" is closer to the facts surrounding the July 3rd Calpine PPA-acquisition offer, but it is not that offer. No Calpine witness, Dr. Hunger included, testifies that FERC will approve the Calpine July 3rd PPA-acquisition proposal on these facts with certainty. There is no guarantee of FERC approval of the proposal under the unique facts of this proposal.

Q. Can you sum up the CPVRR comparison of the July 3rd Calpine final and best offer to the Company's self-build projects when the costs excluded by Mr. Hibbard in his CPVRR adjustments are included in the economic evaluation?

A. Yes. The net effect of the inclusion of all costs in the economic evaluation of the Calpine July 3rd final and best offer, including the costs Mr. Hibbard failed to include in his adjustments to the CPVRR evaluation, demonstrates that the

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Calpine July 3rd final and best offer is less cost effective by [redacted] in a FERC approval scenario and [redacted] to [redacted] less cost effective in a FERC disapproval or FERC mitigation scenario than the Company's self-build generation projects, depending on the length of the eventual PPA. Please see DEF's evaluation of the Calpine July 3rd offer in Exhibit No. ___ (BMHB-18).

IV. DEF EVIDENCE UNCONTESTED BY INTERVENOR TESTIMONY IN THIS DOCKET.

Q. What issues will the Commission decide in this Docket?

A. My understanding is that the Commission will determine:

> (i) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for electric system reliability and integrity;
>
> (ii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for adequate electricity at a reasonable cost;
>
> (iii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for fuel diversity and fuel supply reliability;
>
> (iv) Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to DEF that might mitigate the need for the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project;
>
> (v) Are the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017 the most cost-effective alternative available to meet the needs of DEF and its customers; and
>
> (vi) Did DEF reasonably evaluate all alternative scenarios for cost effectively meeting the needs of its customers over the relevant planning horizon.

Q. Do the NRG and Calpine witnesses challenge the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017 to meet DEF's need for electric system reliability and integrity?

A. No. The NRG and Calpine witnesses support their generation capacity proposals to meet DEF's electric system reliability and integrity needs prior to 2018. They do not challenge the fact that there is a reliability need for generation capacity on DEF's system prior to 2018.

Q. Do the NRG and Calpine witnesses challenge the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017, taking into account the need for fuel diversity and supply reliability?

A. No. In fact, both NRG and Calpine propose existing natural gas-fired combustion turbine or combined cycle generation units as alternatives to meet DEF's need prior to 2018 and the NRG and Calpine plants are served by existing natural gas pipelines in the State, just like the proposed Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project.

Q. Do the NRG and Calpine witnesses challenge whether there are renewable energy sources and technologies or conservation measures that could have been taken or that were reasonably available to DEF that

might mitigate the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017?

A. No. Both NRG and Calpine propose existing supply-side generation resources to meet DEF's reliability need prior to 2018. The NRG and Calpine witnesses do not argue that this need for generation capacity prior to 2018 does not exist because of available renewable energy sources or technologies or conservation measures that DEF could have taken to mitigate its need for generation capacity prior to 2018.

Q. Do the NRG and Calpine witnesses argue that either the proposed Suwannee Simple Cycle Project in 2016, or the Hines Chillers Power Uprate Project in 2017, is not the most cost effective alternative for DEF and its customers to meet the need for generation capacity prior to 2018?

A. The NRG and Calpine witnesses assert that their supply-side generation proposals are more cost effective than the Suwannee Simple Cycle Project to meet DEF's need in 2016, but they do not appear to dispute DEF's evidence that the Hines Chillers Power Uprate Project is the most cost effective alternative to meet DEF's need in 2017. In other words, the NRG and Calpine witnesses appear to concede that the Hines Chillers Power Uprate Project is a cost effective generation capacity resource regardless of the generation capacity resource selected by the Company to meet DEF's other generation capacity needs prior to 2018.

To illustrate, while NRG's witness argues that its proposal that DEF acquire its plant is the most cost effective alternative to meet DEF's need prior to 2018, NRG's witnesses nowhere contest the economic value of the generation provided by the Hines Chillers Power Uprate Project and, in fact, NRG's witness Mr. Pollock proposes the acquisition of the NRG plant and the Hines Chillers Power Uprate project as an alternative, cost effective resource plan to simply acquiring the NRG plant to meet DEF's need prior to 2018. (Pollock Direct Test., p. 23, lines 25-26). Calpine's witnesses similarly argue that the Calpine July 3 proposal, the PPA with an option to purchase the Calpine Plant, is more cost effective than the Company's self-build generation projects to meet DEF's need prior to 2018 with a focus on the comparison of the Calpine generation proposal to the Suwannee Simple Cycle Project. (see, e.g., Thornton Direct Test., p. 15, lines 19-22; Hibbard Direct Test., p. 48, lines 9-12). But Calpine's witnesses concede as they must the economic value of the Hines Chillers Power Uprate project, explaining in their own simplistic cost analysis that the combination of the Calpine proposal and the Hines Chillers Power Uprate project is nearly equivalent to the Calpine proposal by itself. (Hibbard Direct Test., Exhibit No. ___ (PJH-3).

The apparent position of NRG and Calpine with respect to the Hines Chillers Power Uprate Project is consistent with my direct testimony and exhibits in this docket. As I explained there, the addition of the Hines Chillers Power Uprate Project to every generation capacity resource proposal made every proposal more economically favorable for DEF's customers, and therefore, our evaluation of the generation capacity resource proposals to meet DEF's need prior to 2018 included the Hines Chillers Power Uprate Project in every generation resource option. (Borsch Direct Test., p. 40, lines 17-23, p. 41, lines 1-3 and Exhibit No. ___ (BMHB-8). NRG and Calpine witnesses do not dispute this fact; in fact they both suggest the Hines Chillers Power Uprate Project as an alternative resource in addition to their generation capacity proposals, and the Calpine simplistic cost analysis supports the economic value of this Project for DEF's customers.

V. THE NRG AND CALPINE WITNESS CRITICISMS OF DEF'S EVALUATION OF THE MOST COST EFFECTIVE ALTERNATIVE TO MEET DEF'S NEED PRIOR TO 2018 ARE WRONG AND FAIL TO REFLECT AN UNDERSTANDING OF DEF'S IRP, EVALUATION PROCESS, AND SYSTEM REQUIREMENTS.

Q. Do the Calpine and NRG witnesses also criticize DEF's evaluation of the most cost-effective generation alternative to meet DEF's need prior to 2018?

A. Yes. Calpine witness Mr. Hibbard criticizes DEF's evaluation methodology and utility industry-standard resource planning cost models and, therefore, he rejects the results of DEF's evaluation. (Hibbard Direct Test., pp. 9-12, pp. 19-26). He argues that DEF should have used nothing more than a simplistic screening tool to determine the most cost effective generation alternative to meet its need prior to 2018 and, based on his application of that screening tool, he asserts that the Calpine plant is the most cost effective alternative to meet DEF's customer needs prior to 2018. (Hibbard Direct Test., p. 10, lines

6-10, p. 15). Mr. Hibbard's criticisms demonstrate, as I explain in detail below, that he does not understand the utility industry resource planning tools and models that DEF used in its evaluation of the most cost effective generation alternative to meet DEF's need prior to 2018. Further, his own simplistic levelized cost analysis demonstrates that the Suwannee Simple Cycle Project is the most cost effective generation resource to meet DEF's peaking need prior to 2018.

Alternatively, Mr. Hibbard accepts the CPVRR results of the Company's evaluation of the Calpine proposal compared to the Company's self-build generation projects to meet DEF's need prior to 2018 and he makes "adjustments" to those CPVRR calculations based on new inputs resulting from the July 3rd Calpine final and best offer. (Hibbard Direct Test., p. 27, lines 20-23, pp. 28-32). Mr. Hibbard fails to include all costs of the Calpine July 3rd final and best offer and he improperly removes proper costs, such as firm gas transportation costs, in his "adjusted" CPVRR analysis. These errors in Mr. Hibbard's analysis are explained above at pages 33-48 of my rebuttal testimony.

Mr. Hibbard, Mr. Thornton, and Mr. Pollock also criticize DEF's evaluation because they claim qualitative factors favor the Calpine plant or the NRG plant, respectively, rather than the Company's self-build generation projects to meet DEF's generation capacity need prior to 2018. In sum, they claim that, unlike the Company's self-build generation projects, the Calpine plant, or the NRG plant as the case may be, provides DEF customers price certainty, in-service date certainty, operating condition certainty and flexibility, and, in the case of the Calpine plant, better emissions because it is an existing combined cycle unit. (Hibbard Direct Test., p. 6, lines 6-23, p. 7, lines 1-8, p. 34, lines 20-23, pp. 35-36; Thornton Direct Test., p. 10, lines 13-23, pp. 11-13; Pollock Direct Test., p. 9, lines 11-22, pp. 10-11). These witnesses overstate the benefits and ignore the uncertainties associated with the Calpine plant or NRG plant, and the proposals to sell the plants to DEF.

Finally, Mr. Hibbard and NRG witness Mr. Pollock too criticize DEF's load forecast claiming it has errors or is inherently uncertain and, therefore, actual load conditions may deviate from projected load. (Hibbard Direct Test., p. 42, lines 21-22, p. 43; Pollock Direct Test., p. 21, lines 11-16, pp. 22-23). These criticisms are difficult to understand, not only because they are inaccurate, as I explain in detail below, but also because they seem to focus more on the need after 2018 rather than the Company's need that commences prior to 2018. In any event, to the extent these criticisms focus on the need prior to 2018 it is difficult to understand why both Calpine and NRG believe buying their existing units rather than building new generation units cures their claimed errors or uncertainty in the load forecasts.

NRG witness Mr. Pollock also criticizes DEF's evaluation while steadfastly maintaining that one aspect of DEF's evaluation demonstrates that the NRG initial plant acquisition proposal is more cost effective than the Company's self-build generation projects. I will demonstrate that he cannot "pick and choose" what he likes from the evaluation and discard the rest of the evaluation and explain why his recommendation based on part of that evaluation is simply wrong. In part this involves an explanation why his and NRG witness Mr. Dauer's assumptions that DEF can simply buy gas for the NRG plant the way NRG has done so as a merchant plant in the past fail to recognize DEF's obligation to reliably deliver power to customers during all hours, every day on its system. I will also demonstrate that Mr. Pollock fails to understand DEF's evaluation of the generation capacity resource options to meet DEF's need prior to 2018.

A. DEF'S GENERATION RESOURCE ALTERNATIVE EVALUATION.

Q. What are Mr. Hibbard's criticisms about the methodology and tools that DEF used to evaluate the generation resource alternatives to meet its need prior to 2018?

A. Mr. Hibbard criticizes the Company for, in his view, using only the Strategist resource planning model to determine the most cost effective generation alternative to meet DEF's need. (Hibbard Direct Test., p. 19, lines 19-23, p. 20, lines 1-11; p. 21, lines 11-23, p. 22, lines 11-23). He claims this Strategist model lacks transparency, does not adequately represent the value of different generation resource options --- such as a combined cycle unit and a CT unit ---- in the resource selection process, and is a simplistic rather than an hourly production cost dispatch model that unfairly understates the production cost benefit of the Calpine plant. (Id.). Mr. Hibbard claims that the appropriate production cost modeling tool that DEF should have used is a Ventyx or

General Electric "transmission-constrained, hourly production cost modeling program." (Hibbard Direct Test., p. 22, lines 3-9). In fact, as discussed below, DEF did use such a model in its evaluation.

Apparently because of his perceived problems with the Strategist model and his perception that DEF did not use an appropriate hourly production cost modeling tool, Mr. Hibbard argues that a levelized cost analysis is a more appropriate comparison of the Calpine plant to the Company's self-build generation project to meet the Company's need prior to 2018 and, that based on his levelized cost analysis, the Calpine plant actually is more cost effective than the Suwannee Simple Cycle Project to meet DEF's need prior to 2018. (Id.; p. 15).

Q. What modeling analyses were used by DEF in its evaluation of the alternative generation capacity resources to meet DEF's need prior to 2018?

A. DEF used all three types of modeling tools that Mr. Hibbard discusses in his direct testimony in its evaluation of the most cost effective supply-side alternatives to meet its need prior to 2018. DEF first applied an economic evaluation to screen "like type" proposals based on "the fixed and variable payments or costs." (Borsch Direct Test., p. 34, lines 18-22). This is similar if not identical to the "Levelized Cost of Electricity ("LCOE")" analysis that Mr. Hibbard describes in his direct testimony.

DEF next used the Strategist model to identify optimal resource plans corresponding to each proposal, including Calpine's proposal, and the self-build options. I explained the reasons DEF used the LCOE-type screening analysis and the Strategist optimization model in my direct testimony. The LCOE-type screening "compares the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of the Company's base case self-build generation plan." (Borsch Direct Test., p. 36, lines 6-9). DEF, therefore, contrary to Mr. Hibbard's assertions did not rely only on the Company's Strategist analysis in its evaluation of the most cost effective generation resource to meet DEF's need prior to 2018. (Hibbard Direct Test., p. 19, lines 18-22).

DEF used the hourly-production cost model that Mr. Hibbard says DEF should have used in its generation resource evaluation. Mr. Hibbard asserts that DEF should have used "either Ventyx's Promod production cost modeling tool or General Electric's GE MAPS tool" because they are "transmission-constrained hourly production cost modeling programs." (Hibbard Direct Test., p. 22, lines 3-9). DEF used a Ventyx detailed production cost modeling tool --- DEF used the Energy Portfolio Manager ("EPM") detailed production cost model, which is a Ventyx production cost model of newer vintage than the Promod production cost model that Mr. Hibbard identifies in his direct testimony. The Ventyx EPM production cost model is a "transmission-constrained hourly production cost model program." I explain how we used

EPM to produce the CPVRR results for each proposal individually and then compared to the self-build projects in my direct testimony. (See Borsch Direct Test., p. 38, lines 12-23; pp, 39-40).

I can only conclude that Mr. Hibbard does not understand the use of production cost modeling in electric utility resource planning or, at the very least, how DEF uses these modeling tools in its resource planning and generation resource evaluations, or that he either did not read or simply chose to ignore my direct testimony, exhibits, and the discovery responses we have provided the parties explaining our evaluation.

Q. Is Mr. Hibbard's LCOE analysis a better tool to evaluate the most cost effective generation capacity resource alternative to meet DEF's need in 2018?

A. No. The LCOE analysis is a screening tool that should be used to compare "like type" generation resource options based on the fixed and variable payments that Mr. Hibbard identifies for the generation resources. This is exactly the way DEF used this screening tool in its evaluation. (Borsch Direct Test., p. 34, lines 18-20). In other words, this tool is used to compare CT proposals to other CT proposals, combined cycle proposals to combined cycle proposals, and so on, to narrow the number of resource options considered in the production cost modeling evaluation to the best of each type of option, i.e., the best CT proposal and the best combined cycle proposal and so on.

The LCOE analysis is not a good tool to compare different types of resource options, such as a CT proposal to a combined cycle proposal, because the LCOE analysis cannot tell you why you should pick one type of generation resource over another type of generation resource.

The LCOE analysis also does not help the utility understand the impact of adding any type of generation resource evaluated in the LCOE analysis to DEF's generation system. The LCOE analysis is not a dispatch model; it is a simple spreadsheet analysis that allows you to visually compare the costs of like type generation resources. To understand the impact of the generation resource option on DEF's system, DEF must evaluate the generation resource option in a production cost model that includes all generation system costs and dispatches the resource generation option in the most cost effective or economic dispatch for the generation system as a whole.

Mr. Hibbard acknowledges that this information regarding the economic dispatch of the generation resource option on DEF's generation system is the "key difference" between the LCOE analysis and a production cost model and that "production cost modeling can provide important insights and perspectives on resource operations and utilization over time, and on the likely value of resources on the system from an energy benefit perspective." (Hibbard Direct Test., p. 21, lines 11-14, lines 19-20). Mr. Hibbard simply criticizes the Strategist production cost model that DEF used only to identify the optimal resource plans for each alternative evaluated, ignores the Ventyx EPM hourly production cost model that DEF did use to obtain the admittedly "important insights and perspectives on resource operations and utilization over time" and "likely value" of resources from an "energy benefit perspective," and instead testifies that DEF should have used the LCOE analysis that provides none of these benefits.

Q. Do you agree with his criticisms regarding the Strategist model?

A. No. The Strategist model is a well-accepted utility industry production cost model that is used, for example, not only by DEF for resource optimization evaluations, but also by Gulf Power Company and the Southern Company utilities. Mr. Hibbard is correct that Strategist is not an hourly production cost model, and therefore, it necessarily is a more simplistic production cost model than a hourly production cost model like the Ventyx EPM hourly production cost model that DEF uses in resource planning. This, of course, is part of what makes the Strategist model a useful resource planning tool; it is more simplistic than an hourly production cost model and, therefore, with its flexible and powerful optimization engine, can be used more easily and in less time to evaluate optimal resource generation plans.

All of Mr. Hibbard's specific criticisms about the Strategist model --- beyond his vague claims that it is "opaque," "lacks transparency," and a "black box," which all mean the same thing (and with which I disagree) --- relate to the fact that the Strategist model is <u>not</u> an hourly production cost model. (Hibbard Direct Test., p. 22, lines 11-23, p. 23, lines 1-12). As I explained above, he does not know or he chooses to ignore that DEF also used the EPM hourly production cost model in its evaluation. Nowhere in his testimony does Mr. Hibbard criticize the EPM hourly production model – he in fact says DEF should use it --- nor does he criticize DEF's use of the EPM hourly production model in its evaluation of the generation resource options, including Calpine's proposal, to meet DEF's need prior to 2018.

Q. What do you make of Mr. Hibbard's criticism regarding the additional generation that is added to the DEF system in the Strategist model to meet the Reserve Margin requirement over the evaluation period?

A. It is difficult to understand Mr. Hibbard's criticism. He seems to say on page 23 that DEF is "building" more combined cycle generation than DEF needs to meet the annual growth in energy that he projects between 2018 and 2043, but then he expressly states on the next page of his direct testimony that he is not testifying that DEF is overbuilding combined cycle generation. (Hibbard Direct Test., p. 23, lines 13-23; p. 24, lines 15-17). I assume his point is that the only combined cycle generation that DEF should add to its system in this time period is Calpine's combined cycle generation plant. But, of course, if his point is that DEF is adding more combined cycle generation than DEF needs, then, DEF doesn't need the Calpine combined cycle generation plant either.

Mr. Hibbard's real concern is that, assuming DEF contracted for and acquired the Calpine plant in 2014, over time the capacity factor of the Calpine plant falls off and the number of starts increase for the Calpine plant as new, more efficient combined cycle generation is added to DEF's system. That is

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the point of Exhibit No. ___ (PJH-6). This means that new generation on DEF's system affects the cost effectiveness of the Calpine plant as a DEF generation system resource in the DEF resource evaluation. So Mr. Hibbard develops a chart comparing the projected energy growth on DEF's system to the projected growth in potential new combined cycle generation from 2018 to 2043 to claim that DEF doesn't need all the new combined cycle generation in its resource evaluation that is negatively affecting the value of Calpine's plant in the production cost dispatch analysis of the system. See Exhibit No. ___ (PJH-5). What Mr. Hibbard has done to create this apparent "overbuild" in future combined cycle generation capacity is to assume that <u>all</u> the existing and new combined cycle generation will <u>always</u> operate at a [redacted]. That assumption is obviously unrealistic and incorrect.

The whole point of resource planning is to add additional generation capacity when it is economic to do so to meet system reliability needs. Arbitrarily forcing the production cost model to run older, more costly to operate and maintain, and less fuel efficient units on the system will yield an overall more expensive system for customers than allowing the production cost model to select the most cost efficient resources even if that means adding new generation and reducing the operation of existing generation on the system. What Mr. Hibbard fails to mention is that the Calpine plant runs at a capacity factor of [redacted] from 2014 to 2026 in his own Exhibit No. ___ (PJH-6) when the Calpine plant is 10 to 22 years old. Of course, the Calpine plant operation will fall off when the plant is over 20 years old as new,

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more fuel efficient generation units are added to the system. DEF's existing, older generation units on the system are not immune from these effects, the same thing happens to the capacity factor and number of starts for DEF's existing combined cycle generation.

Q. You testified that the LCOE analysis that Mr. Hibbard recommends should only be used to compare "like type" resources. Does Mr. Hibbard use the LCOE analysis to compare "like type" resources?

A. No. Mr. Hibbard uses his LCOE analysis to compare combined cycle generation – the Calpine plant – to CT generation --- the Suwannee Simple Cycle Project. It should not surprise anyone in the utility industry that combined cycle and CT generation have different capital, fixed and variable operation and maintenance ("O&M"), and other costs and different capacity factors. Using the LCOE analysis to make a selection between these two different resource options is not a meaningful exercise to determine which generation option is the most cost effective generation on DEF's system.

Mr. Hibbard's Exhibit No. ___ (PJH-3) illustrates this point. According to Mr. Hibbard, Exhibit No. ___ (PJH-3) demonstrates that the Calpine asset sale at $85.3 ($2014/MWh) is more cost effective than the DEF Suwannee Simple Cycle Project at $168 ($2014/MWh). But Mr. Hibbard is comparing the Calpine asset sale value at a [redacted] capacity factor to the value of the Suwannee Simple Cycle Project at a 9.3 percent capacity factor, which is the expected capacity factor for the Suwannee Simple Cycle Project. See Exhibit

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No. ___ (PJH-4). If Mr. Hibbard is suggesting that DEF should always compare combined cycle generation costs on a $/MWh basis at a [redacted] capacity factor to CT generation on a $/MWH basis at a roughly 9 percent capacity factor, then, DEF --- or any other public utility for that matter --- will always select the combined cycle generation over the CT generation. Since this will never be the case in the real world where DEF and every other public utility will build generation to meet base, intermediate, and peaking load the LCOE analysis is clearly a meaningless exercise when the utility must determine what type of generation is the most cost effective generation on its system.

Q. Based on DEF's actual system need prior to 2018, does Mr. Hibbard's LCOE analysis tell you anything about the most cost effective generation resource to meet that need?

A. It could be read this way. DEF identified a peaking generation need prior to 2018 and that is why the production cost model evaluations in DEF's IRP process identified the Suwannee Simple Cycle Project in 2016. Based on DEF's need for peaking generation on its system prior to 2018, Mr. Hibbard's own exhibit demonstrates that the Suwannee Simple Cycle Project is more cost effective than the Calpine plant. On Exhibit No. ___ (PJH-4), at any capacity factor below [redacted], the Suwannee Simple Cycle Project is more cost effective on a $/MWh basis than the Calpine plant. At the expected capacity factor of 9.3 percent for the Suwannee Simple Cycle Project, then, the Company's self-build peaking generation resource is much more cost effective than the Calpine plant.

This is an expected result. Mr. Hibbard admits that "CT capacity is effective providing capacity at times of system peak or otherwise when stressed system conditions require operation of peaking capacity." (Hibbard Direct Test., p. 38, lines 18-20). If DEF needs generation capacity to meet system peak load, then, Mr. Hibbard admits that CT generation like the Suwannee Simple Cycle Project is the effective capacity to meet that need.

In fact, this exactly demonstrates the weakness of LCOE as a stand-alone evaluation methodology. If the analysis assumes a particular use or capacity factor for a given unit, then, the LCOE will almost always support the selection of a unit designed for that service. A more detailed production cost model such as EPM will re-dispatch resources to allow different resources to operate at an optimum capacity factor in the context of the whole portfolio. This allows comparison of different types of resources in light of their impact on the total production cost.

Peaking generation capacity is an effective addition to the DEF fleet prior to 2018. Calpine witness Mr. Thornton is wrong when he says DEF is replacing base load generation due to the retirement of CR3 and the near-term retirement of CR1 and CR2. (Thornton Direct Test., p. 12, lines 8-11). DEF is replacing base load and intermediate generation due to the CR3 retirement and the planned CR1 and CR2 retirement with the Citrus County Combined Cycle Power Plant that is the subject of DEF's Petition in Docket No. 140110-

EI. Prior to the addition of the Citrus County Combined Cycle Power Plant in 2018, the Company can effectively utilize peaking generation capacity and that is why DEF identified the Suwannee Simple Cycle Project as the most cost effective self-build generation capacity option in 2016.

Q. If DEF needs peaking generation capacity prior to 2018, why did DEF consider the Calpine proposal in its evaluation?

A. DEF is always looking for the best overall value for its customers. Even though DEF had identified a peaking generation capacity need prior to 2018, and the Suwannee Simple Cycle Project to meet that need in 2016, DEF would have considered any alternative generation capacity resource option that offered more overall value to customers than the Company's peaking generation self-build option, including the Calpine proposal. As in all comparisons between combined cycle and peaking units, the combined cycle must provide enough operating cost savings in the context of the whole fleet to offset the higher capital cost of the combined cycle. In our evaluation in this case, however, Calpine's reduced acquisition price closed part of, but not all of, the gap between its revised July 3rd offer and the Company's self-build generation, thus, the Suwannee Simple Cycle Project remains the most cost effective generation resource option to meet DEF's need in 2016.

B. DEF REASONABLY CONSIDERED THE QUALITATIVE FACTORS OF ALL PROPOSALS TO MEET DEF'S NEED PRIOR TO 2018.

Q. Mr. Hibbard, Mr. Thornton, and Mr. Pollock all claim that DEF did not appropriately evaluate the qualitative value that their existing Calpine and NRG plants, respectively, provide. Do you agree with them?

A. No. DEF does not understand their claim that DEF did not evaluate these factors in its evaluation. DEF did consider these factors in its evaluation. They are included in Exhibit No. ___ (BMHB-9) and discussed in my direct testimony. (Borsch Direct Test., pp. 41-42 and 46-48). These witnesses simply do not like the fact that this analysis also included qualitative risks associated with the Calpine and NRG proposals and they do not like the results of DEF's evaluation of all the qualitative factors or risks, including the qualitative factors or risks associated with the Calpine and NRG acquisitions. (Id.).

The undisputed fact that the Calpine and NRG plants currently exist and the Suwannee Simple Cycle Project must be built does not render their projects qualitatively more favorable than the Suwannee Simple Cycle Project. First, with respect to the construction and in-service date risk, the cost of the Suwannee Simple Cycle Project accounts for these risks. (Borsch Direct Test., p. 41, lines 5-11; Exhibit No. ___ (BMHB-9)). Second, DEF knows how to build and has built similar projects to the Simple Cycle Project on time and on budget. See Exhibit No. ___ (BMHB-19) to my rebuttal testimony. Finally, DEF further has made it clear in this Docket that, given the unique circumstances of this Petition, DEF accepts the fact that it will be bound by the cost estimate of its self-build projects unless DEF can demonstrate that any cost increase was prudent and point to specific reasons to justify the increase.

In addition, there is no greater price certainty associated with the Calpine and NRG proposals, despite their claims to the contrary. Many terms affecting the price of the plant acquisitions remain to be negotiated with both final and best offers. For example, Mr. Thornton admits the Calpine purchase price was "subject to certain adjustments the terms of which would be negotiated." (Thornton Direct Test., p. 8, lines 15-17).

Likewise, there is substantial uncertainty with respect to the plant condition and operational capability of both plants under both the Calpine and NRG final and best offers. Both Calpine and NRG tout the <u>past</u> performance and operational capabilities of their plants, but past performance is no guarantee of future plant performance, and DEF was buying both plants under their final and best offers <u>in the future</u>. At that future point in time, there were no guarantees of performance and terms addressing the condition of the plant in the final and best offers, and the rights of the parties based on the plant condition at that future point remained undetermined and, thus, uncertain. (See Exhibits Nos. ____ (BMHB-12) and ___ (BMHB-13).

In sum, despite the fact that the Calpine and NRG plants currently exist, there remain unknown terms and conditions associated with their final and best offers for those existing plants that make it clear that the claimed price and operational performance certainty that the Calpine and NRG witnesses tout simply do not exist. There is no reason to believe that these unknown terms and conditions associated with their final and best offers are qualitatively less risky to the Company than completing the construction of a standard CT plant much like Duke Energy has done many times before.

C. DEF'S LOAD FORECAST IS REASONABLE AND DEMONSTRATES DEF'S NEED FOR ADDITIONAL GENERATION CAPACITY PRIOR TO 2018.

Q. You testified that the NRG and Calpine witness testimony with respect to DEF's load forecast is difficult to understand. Can you explain what you mean?

A. NRG witness Mr. Pollock and Calpine witness Mr. Hibbard to a lesser degree criticize DEF's load forecast and resource plan to meet that load in their direct testimony. (Hibbard Direct Test., p. 42, lines 21-22, p. 43; Pollock Direct Test., p. 21, lines 11-16, pp. 22-23). NRG and Calpine filed this direct testimony in this Docket and in Docket 140110-EI, which involves DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant in 2018. While unclear, NRG witness Mr. Pollock and Calpine witness Mr. Hibbard in part of their direct testimony appear to be addressing DEF's need in 2018 and beyond, and, as a result, I have filed rebuttal testimony in Docket 140110-EI addressing this part of their direct testimony. Indeed, one reason I am unclear if these witnesses intended to direct this part of their testimony to DEF's need prior to 2018 is that they both claim that DEF should have selected their acquisition proposals and buying their existing plants to add generation capacity rather than building new generation capacity still does not cure any claimed errors or uncertainty in DEF's load forecast. To the extent that Mr. Pollock or Mr. Hibbard are asserting these arguments in this Docket, I am providing the same rebuttal testimony to these arguments below that I provided in Docket No. 140110-EI in this Docket.

Q. Do the NRG and Calpine witnesses claim that there are errors in DEF's load forecast or load forecast methodology?

A. NRG witness Mr. Pollock appears to claim there is a load forecast error affecting DEF's generation capacity needs, but Calpine witness Mr. Hibbard does not claim there are errors in DEF's load forecast or load forecast methodology. (Pollock Direct Test., pp. 21-22). In fact, Calpine witness Mr. Hibbard specifically says that he did not find anything wrong with DEF's forecasts of load/energy growth or the timing of resource additions or retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). He admits there will be growth in peak load and energy requirements. (Hibbard Direct Test., p. 43, lines 3-4). Ironically, despite apparently claiming an error in DEF's load forecast, NRG witness Mr. Pollock also concedes it is also possible that load growth could be higher than what DEF projects in its load forecast. (Pollock Direct Test., p. 23, lines 6-9). Both witnesses were provided the same DEF load forecast.

Q. What is the load forecast error that NRG witness Mr. Pollock apparently asserts occurred in DEF's load forecast?

A. NRG witness Mr. Pollock asserts that DEF's need for capacity prior to 2018 is driven primarily by a more than 1,000MW increase in both wholesale and peak demand in 2014-2015. He then claims that, because DEF has not actually experienced such significant load growth in any two years since 2005, there is some unasserted reason to believe there may be a risk of load forecast error in DEF's load forecast. Based on this belief, NRG witness Mr. Pollock assumes an arbitrary 50 percent reduction in DEF's load forecast and develops an argument and exhibits to support his unremarkable conclusion that DEF would not need its planned capacity additions in the 2014 to 2023 time frame if you assumed DEF's load was half of what DEF projects it to be in this time frame. (Pollock Direct Test., p. 21, lines 11-16, p. 22, lines 1-21, Exhibit Nos. ___ (JP-2) and ____(JP-3).

Q. Is there an error in DEF's load forecast?

A. No. NRG witness Mr. Pollock selectively chooses the years in DEF's load forecast to focus on to generate his claimed greater than 1,000MW increase in 2014-2015 that, according to him, is out of line with DEF's load growth for the last ten years. A more comprehensive evaluation of DEF's load forecast demonstrates that there is no such dramatic deviation in DEF's load forecast and that any deviations that do exist are readily explained by changes in DEF's wholesale contracts and retail load during the period selected by Mr.

Pollock. In addition, Mr. Pollock chooses as his reference the actual firm generation peak, net of all load control, for 2013, which was a milder than average summer, and then compares that to the 2014 and 2015 projected total, which are necessarily based on normal weather.

DEF's load forecast is contained in the Company's 2014 Ten Year Site Plan ("TYSP") attached as Exhibit No. ____ (BMHB-2) to my direct testimony. True, based on that load forecast in Schedule 3.1, there is a greater than 1,000MW increase in the net firm demand from 2013 to 2015. But, there is a relatively negligible increase of approximately 100MW in net firm demand from 2010 to 2015. It matters, then, what years you choose to compare in the Company's load forecast as to what conclusions you may draw from the forecast and when comparing actual past years to projected future years what the actual weather conditions were.

Further, the claimed dramatic changes in the load forecast that NRG witness Mr. Pollock claims exist based on the years he selected to compare can be explained in part by changes in the Company's wholesale power contracts during this period of time and the comparison between actual wholesale load and DEF's future commitments.

Additionally, DEF is projecting an increase in retail load from 2013 to 2014 as the Florida economy continues to improve and DEF continues to add customers. This projected increase in retail demand from 2013 is only 200MW greater than the increase in retail load DEF actually experienced from 2012 to 2013 as the Florida economy was just starting to improve after the recession and customer growth was expanding. This continued retail load growth in 2014 and 2015 is certainly reasonable based on what DEF experienced from 2012 to 2013 and what is projected to occur as the Florida economy continues to improve. Again, Calpine witness Mr. Hibbard reviewed the same load forecast and found nothing wrong with the Company's load forecast. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). And, as I explained above, NRG witness Mr. Pollock himself admits it is possible load growth could be higher than DEF forecasts it to be. (Pollock Direct. Test., p. 23, lines 6-9).

Q. Is there any reason to conclude from DEF's load forecast as NRG witness Mr. Pollock does that there could be a 50 percent reduction in DEF's load growth during the next ten years?

A. No. As I explained above, Mr. Pollock's claimed potential "error" based on his selective reading of DEF's load forecast is not an "error" at all. Even apart from this assertion by Mr. Pollock, however, there is no reasonable basis that I can see for Mr. Pollock to assume a 50 percent reduction in DEF's load growth and he provides none in his direct testimony. He appears to simply have arbitrarily selected 50 percent as his projected reduction in DEF's load forecast in order to make a point. He may draw as many bar charts as he likes showing that if you reduce DEF's projected load growth by 50 percent it results in 50 percent excess capacity, but that result, of course, naturally flows from his arbitrary assumption that there is a 50 percent reduction in DEF's projected load. (Pollock Direct Test., Exhibit Nos. ___ (JP-2) and ____ (JP-3).

Q. If Calpine witness Mr. Hibbard found no errors in DEF's load forecast what does he say the Commission should do with DEF's load forecast?

A. While Mr. Hibbard expressly says he is not suggesting that the Commission "second-guess" the Company's planning efforts (Hibbard Direct Test., p. 43, line 5), that is, in effect, exactly what he asks the Commission to do. He argues the Commission should "provide flexibility around the timing of the" Citrus County Combined Cycle Power Plant because he says he has recognized, "based on his decades of experience as a utility regulator and consultant," that load forecasts are based on assumptions and actual load will almost certainly deviate from the prior assumptions about that load. (Hibbard Direct Test., p. 43, lines 6-10). He claims that the one resource that provides the Commission this "needed flexibility" around the timing of the Citrus Combined Cycle Power Plant that he identifies in his testimony is the Company's acceptance of Calpine's proposal for a PPA with a purchase option to meet the Company's need prior to 2018. (Hibbard Direct Test., p. 43, lines 17-23).

Q. Does Mr. Hibbard identify any error in the assumptions in DEF's load forecast or any assumptions that he believes based on his decades of experience should be changed?

A. No. He in fact said there was nothing wrong with the Company's load forecast or the timing of its resource additions and retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). That must mean Mr. Hibbard finds nothing wrong with the timing of the Suwannee Simple Cycle Project, the Hines Chillers Power Uprate Project, or the Citrus County Combined Cycle Power Plant.

Mr. Hibbard does refer to the discussion of the accuracy of the utility retail load and energy sales forecast in the Commission's review of the 2013 TYSPs, but it is unclear what he intends the Commission to do with this information. It is hardly surprising that the absolute average error in retail energy sales has increased in "recent years" when Florida has experienced the worst recession since the Great Depression during those years. (Hibbard Direct Test., p. 43, lines 10-12). DEF and other utilities have struggled along with all economic forecasters to properly anticipate the length of the recession and the timing and rate of the recovery. Mr. Hibbard does not suggest that the Commission do anything with this information, and rightly so, because such aberrational economic conditions cannot be accurately predicted and certainly should not be included as an appropriate assumption for a utility's annual load forecasts.

Mr. Hibbard also notes that the "best" forecasts -- which include the Company's load forecasts -- have proven to be accurate to within 1 to 3 percent a year. (Hibbard Direct Test., p. 43, lines 12-16). DEF agrees that it has a demonstrated record of load forecast accuracy. Mr. Hibbard incorrectly concludes, however, that the minor deviations in the accuracy of the annual utility load forecasts can be compounded over several years, thus, leading to significant variations in actual demand. Mr. Hibbard ignores the fact that utilities, including DEF, update their load forecasts regularly, including each year in the utility TYSP. If reasons exist to deviate from prior year forecasts, the load forecasts will be revised, and therefore, there is no statistical or reasonable basis to conclude that prior year deviations in load forecast accuracy can simply be summed up or compounded to determine the overall accuracy of the utility's load forecast. Exhibit No. ____ (BMHB-20) to my rebuttal testimony shows DEF's summer load forecasts over the last six years. This Exhibit shows that DEF updates its load forecast to anticipate the duration and recovery from the recession as well as other trends in expected demand.

In sum, then, his apparent contention that the Commission should simply depart from the assumptions in the Company's load forecasts and the Company's planned generation capacity additions to meet that projected load in DEF's resource plan because actual load conditions in the future may deviate from the assumed load conditions is unprincipled resource planning. The same assertion could be made to justify any deviation anyone wants to make from every single utility load forecast and resource plan because no forecast is absolutely accurate and actual conditions will always deviate to some degree from forecasted conditions. Despite the fact that actual load may be different from what DEF projects it to be DEF must still plan to meet that future load based on reasonable assumptions about future load conditions and resources to meet that load. That is the very nature of DEF's IRP process that is presented to the Commission each year in the utility TYSP and reviewed by the Commission to determine if it is suitable for planning purposes. Mr. Hibbard has not identified any error in that IRP process or any principled resource planning reason for the Commission to deviate from the Company's conclusions based on that IRP process.

D. NRG IS INCORRECT THAT THE NRG ACQUISITION 1 PROPOSAL IS MORE COST EFFECTIVE THAN THE COMPANY'S SELF-BUILD GENERATION PROJECTS.

Q. Can you summarize the position of NRG's witnesses in this Docket?

A. Yes. NRG witness Mr. Pollock, and NRG witness Mr. Dauer too apparently, argue that DEF should have selected the NRG plant acquisition --- the Acquisition 1 proposal --- that NRG submitted in response to the Company's fall 2013 request for renewed proposals to meet DEF's 2018 need. (Pollock Direct Test., p. 6, lines 18-21; Dauer Direct Test., p. 3, lines 4-10). This is the same proposal that DEF evaluated against its Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project and determined, based on all quantitative and qualitative factors, was not a more cost effective resource than the Company's self-build generation projects to meet DEF's need prior to 2018. (Borsch Direct Test., pp. 33-48).

Q. Is the NRG Acquisition 1 proposal NRG's final and best offer?

A. No, it is not. NRG's final and best offer is included as Exhibit No. ___ (BMHB-14) and the Company's evaluation of the NRG final and best offer is included as Exhibit No. ___ (BMHB-15) to my rebuttal testimony. I address NRG's final and best offer in my rebuttal testimony above.

NRG witnesses Mr. Pollock and Mr. Dauer do not describe or even mention NRG's final and best offer in their direct testimony. They do not recommend NRG's final and best offer to the Commission --- they in fact recommend NRG's earlier Acquisition 1 proposal and argue that DEF should have selected the Acquisition 1 proposal. The Acquisition 1 proposal is <u>less</u> cost effective than NRG's final and best offer compared to the Company's self-build projects. In other words, NRG witnesses argue that DEF should have selected NRG's <u>least</u> cost effective proposal.

Q. If the NRG Acquisition 1 proposal was not more cost effective than the Company's self-build generation projects, why do the NRG witnesses argue that DEF should have selected it to meet DEF's need prior to 2018?

A. NRG witness Mr. Pollock at first focuses <u>solely</u> on <u>part</u> of DEF's economic analysis, its <u>initial</u> detailed economic analysis, and claims that this analysis demonstrates that the NRG Acquisition 1 proposal was the most cost effective generation capacity resource to meet DEF's need prior to 2018. (Pollock Direct Test., p. 8, lines 7-17). DEF's <u>initial</u> detailed economic analysis did show that the NRG Acquisition 1 proposal was marginally more cost effective than the Company's Suwannee Simple Cycle Project, but essentially equivalent on a CPVRR basis over the 30-year study period. (Borsch Direct Test., p. 40, lines 4-15; Exhibit No. ___ (BMHB-8)).

This was not the end of DEF's evaluation, however, DEF went on to the next steps in its evaluation which included the cost risk sensitivities analyses, its final detailed economic evaluation, and its qualitative analyses, which included the FERC Competitive Analysis Screen. (Borsch Direct Test., pp. 41-48; Exhibit No. ___ (BMHB-9). Based on the complete evaluation of the NRG Acquisition 1 proposal and other generation capacity proposals, DEF concluded that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost effective alternatives to meet the Company's need in 2016 and 2017.

Q. Do the NRG witnesses argue that the NRG Acquisition 1 proposal should be selected over other resource options based only on the initial detailed economic analysis?

A. No. Despite contending that the NRG Acquisition 1 proposal is the most cost effective option based solely on DEF's initial detailed economic analysis, NRG witness Mr. Pollock agrees that the NRG Acquisition 1 proposal should not be selected simply because it is less expensive over the 30-year period than other resource options in the Company's initial detailed economic analysis. (Pollock Direct Test., p. 11, lines 8-11). He concedes the "cost-effectiveness analysis should not be the sole deciding factor" and that "the Commission should use qualitative criteria in addition to the quantitative cost-effectiveness analysis to determine the resources best suited for meeting DEF's" need. (Pollock Direct Test., p. 11, lines 17-18, lines 23-24). Mr. Pollock ignores, however, most of the qualitative factors that led DEF not to select the NRG Acquisition 1 proposal, many of which DEF asked NRG to address in its final and best offer. These factors are listed on page 47 of my direct testimony.

Q. What factors does Mr. Pollock focus on in his direct testimony?

A. Mr. Pollock makes four claims. First, he claims DEF over-stated the fixed costs associated with the firm gas transportation for the NRG plant in DEF's evaluation of the Acquisition 1 proposal. This is the primary cost risk associated with the NRG Acquisition proposal and addressed in Exhibit No. ___ (BMHB-9) to my direct testimony that rendered the Acquisition 1 proposal uneconomic. Second, Mr. Pollock claims that DEF misapplied the FERC Competitive Analysis Screen in eliminating Acquisition 1 as a viable alternative. Third, Mr. Pollock claims that DEF improperly included imputed debt as a cost in its detailed economic evaluation. Finally, Mr. Pollock argues that DEF did not account for the qualitative benefits of price and operational performance certainty provided by the existing NRG plant. I already addressed this argument in my rebuttal testimony above.

Q. Did DEF over-state the fixed costs associated with the firm gas transportation for the NRG plant?

A. No. Mr. Pollock argues that DEF ignored the existing fuel supply arrangements for the NRG plant in its evaluation but defers to NRG witness Dauer to explain these arrangements. (Pollock Direct Test., p. 10, lines 10-14). Not only did we not ignore these existing fuel supply arrangements in our evaluation of Acquisition 1, we were much very aware of the inadequacies of these arrangements to meet DEF's needs for a system of this type, and had identified this as the principle cost risk associated with the NRG plant acquisition. (Borsch Direct Test., p. 41, lines 14-22; Exhibit No. ___ (BMHB-9). Simply put, if DEF acquired the NRG plant DEF must have sufficient firm gas transportation for all of the plant's capacity to meet peak load needs, otherwise, I could not designate the NRG plant as firm power to meet DEF's Reserve Margin requirements. DEF, unlike NRG, has a statutory obligation to reliably provide electric service to its customers.

I have read Mr. Dauer's direct testimony and it only confirms my concerns with NRG's proposed firm gas transportation for the NRG plant. Mr. Dauer makes no attempt to understand DEF's need as a public utility with a statutory obligation to provide electric service to customers for firm gas transportation for the plant on DEF's system. Rather, Mr. Dauer relies on NRG's past experience operating the NRG plant as an Independent Power Producer. NRG's past experience is no guarantee of the future operation of the plant and DEF is a public utility, not an Independent Power Producer.

Mr. Dauer argues that NRG has managed to obtain gas on a non-firm or spot market basis, at an unspecified price, when NRG needed it to meet the power needs of another utility with different system requirements. (Dauer Direct Test., pp. 5-10). Mr. Patton provides rebuttal testimony to explain DEF's firm gas transportation requirements and why Mr. Dauer's past NRG experience is not an adequate future plan for DEF if it acquired the NRG plant. I can add as the director of resource planning for DEF that I am not prepared to "gamble" on non-firm gas transportation on the market being available at a reasonable price for customers at peak hours when the plant is most needed.

Q. Does Mr. Pollock explain his claim that the Company misapplied the FERC market screen?

A. No. Mr. Pollock defers to NRG witness Dr. Morris. Julie Solomon has filed rebuttal testimony to Dr. Morris' direct testimony. I can add, however, that the NRG Acquisition 1 proposal that Mr. Pollock recommends was analyzed by Ms. Solomon and Ms. Solomon determined that it failed the FERC Competitive Analysis Screen. Neither Mr. Pollock nor Dr. Morris disputes that analysis.

Q. Did DEF improperly include imputed debt in its economic evaluation of the NRG Acquisition 1 proposal?

A. No. The NRG Acquisition 1 proposal that NRG witness Mr. Pollock says DEF should have selected is, as indicated by the name of the proposal, a plant acquisition proposal. There is no imputed debt cost for a plant acquisition.

In addition, while the cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure as a result of the fixed future payment obligations under the PPA, I explained that, in this case, because the PPA terms were all five years or less, the impact of imputed debt was immaterial. (Borsch Direct Test., p. 39, lines 15-23, p. 40, lines 1-2). As a result, the cost of imputed debt was not included in the final detailed economic analysis for even the PPAs that were evaluated.

Q. Does Mr. Pollock make any additional arguments in support of the NRG Acquisition 1 proposal?

A. Yes. Mr. Pollock makes an extended argument regarding DEF's customer rates. This argument is irrelevant in this proceeding. The Commission will determine in this proceeding if DEF has demonstrated the most cost effective generation capacity resource to meet its need for generation capacity prior to 2018. The customer price impacts as a result of the most cost effective generation resource to meet the need for generation capacity prior to 2018 will be what they will be. The point is, if DEF had demonstrated a need for generation capacity prior to 2018 --- which is uncontested by any NRG or Calpine witness in this Docket --- then the decision in this Docket is what is the most cost effective generation to meet that need for generation capacity.

VI. CONCLUSION.

Q. Have the NRG or Calpine witnesses presented any evidence that their recommended generation capacity resources to meet DEF's need for

generation capacity prior to 2018 are more cost effective alternatives to meet the Company's reliability needs in the summers of 2016 and 2017?

A. No. The Company evaluated market proposals for alternative generation to meet its need for generation capacity in the summers of 2016 and 2017 --- including NRG and Calpine PPA and plant acquisition proposals --- and the Company determined, for the reasons provided in my direct testimony, that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were more cost-effective, on a quantitative and qualitative basis, than any of the alternative supply-side generation proposals. The NRG and Calpine witness testimony in this Docket does not change this determination.

To begin with, no NRG or Calpine witness directly challenges the cost-effectiveness of the Hines Chillers Power Uprate Project as a generation capacity resource to meet DEF's reliability need in the summer of 2017. Their testimony focuses on the comparison of their generation capacity proposals to the Suwannee Simple Cycle Project. It is undisputed, then, that the Hines Chillers Power Uprate Project is the most cost effective generation capacity resource to meet DEF's reliability need in the summer or 2017.

Calpine and NRG both submitted final and best offers after DEF filed its Petition and direct testimony and exhibits in this Docket because they obviously recognized their initial generation capacity proposals proved to be less cost effective than the Suwannee Simple Cycle Project. These proposals moved closer to the cost effectiveness of the Suwannee Simple Cycle Project, but they still were not more cost effective than that Project to meet DEF's need for generation capacity in the summer of 2016.

Calpine continued to press the cost effectiveness of its final and best offer in its Direct Testimony in this Docket. Calpine's primary expert witness Mr. Hibbard deliberately ignores or does not understand DEF's evaluation models and tools, criticizes DEF for not employing production cost economic dispatch models that DEF in fact employed, and urges the Commission instead to use his results from a simplistic screening tool for "like type" resources to evaluate different types of resources without understanding the costs and benefits of the dispatch of the resource on DEF's system. This is not a detailed economic analysis of the proposals or a fair and accurate criticism of DEF's detailed economic analysis of the alternative generation resource options to meet its reliability need commencing in the summer of 2016. That detailed economic analysis, which includes an analysis of the economic dispatch of the alternative resources on DEF's system using the very model Mr. Hibbard said DEF should use, demonstrates that DEF has a need for peaking generation capacity in the summer of 2016 and that the Suwannee Simple Cycle Project is the most cost effective generation capacity resource to meet that need. Even the simplistic screening tool Mr. Hibbard used demonstrates that, if peaking generation capacity is needed, the Suwannee Simple Cycle Project is more cost-effective to meet that need than the Calpine plant.

NRG retreated from its final and best offer to its initial plant acquisition proposal. On a quantitative and qualitative basis, which NRG witness Mr. Pollock agrees is the right evaluation approach, the initial NRG plant acquisition is not more cost effective than the Suwannee Simple Cycle Project. Firm natural gas transportation at all times for all the plant's capacity is an absolute necessity for DEF to rely on this plant as a firm resource to meet DEF's obligation to provide reliable electric service at all times to its customers. DEF simply cannot and will not "gamble" on natural gas transportation being available at a reasonable price on the spot market when DEF needs that plant to reliably serve its customers in the manner that NRG as an Independent Power Producer with no obligation to serve has operated the NRG plant in the past. Further, the NRG plant acquisition fails the FERC Competitive Analysis Screen, preventing DEF from acquiring the NRG plant. No NRG witness disputes the fact that the initial plant acquisition failed the FERC market screen that must be passed to obtain FERC approval for the acquisition.

In sum, the Suwannee Simple Cycle Project is the most cost effective generation capacity resource, on a quantitative and qualitative basis, to meet DEF's need for generation capacity commencing in the summer of 2016. The Suwannee Simple Cycle Project is a new, state-of-the-art CT plant with higher fuel efficiency than existing CT plants located at an existing DEF power plant site where it benefits from the shared resources and further provides transmission stability in the area. It is the most beneficial generation capacity resource to meet DEF's peaking generation capacity needs commencing in the summer of 2016.

For all these reasons, and the reasons provided in DEF's Petition and direct testimony and exhibits in this Docket, DEF requests that the Commission grant DEF's Petition and approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-12)
Pages 1 through 49

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

EXHIBIT BMHB-12 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-13)
Pages 1 through 51

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

**EXHIBIT BMHB-13 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY**

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-14)
Pages 1 through 3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

**EXHIBIT BMHB-14 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY**

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-15)
Pages 1 through 9

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

**EXHIBIT BMHB-15 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY**

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-16)
Pages 1 through 4

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

DOCKET NO. 140111-EI
Submitted for filing:
August 5, 2014

EXHIBIT BMHB-16 OF REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION IN ITS ENTIRETY

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-17)
Pages 1 through 2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

EXHIBIT BMHB-17 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-18)
Pages 1 through 3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

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Submitted for filing:
August 5, 2014

**EXHIBIT BMHB-18 OF
REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH
IS COMPETITIVELY SENSITIVE CONFIDENTIAL INFORMATION
IN ITS ENTIRETY**

DEF's Summary of Similar Capital Projects to
the Suwannee Simple Cycle Project

Project	Originally Project Cost ($Millions including AFUDC)	Actual Cost ($Millions including AFUDC)
Buck CC - 2011	$700	$664
W.S. Lee CT - 2006	$66	$57
Hines CC PB3 - 2005	$230 (not including AFUDC	$231 (not including AFUDC)
Hines CC PB4 - 2007	$262	$269
Bartow CC - 2009	$765	$641
H.F. Lee CT - 2009	$90	$84
H.F. Lee CC - 2012	$903	$715
Dan River CC - 2012	$716	$662
Sutton CC - 2013	$731	$560

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Exhibit No. ____ (BMHB-20)
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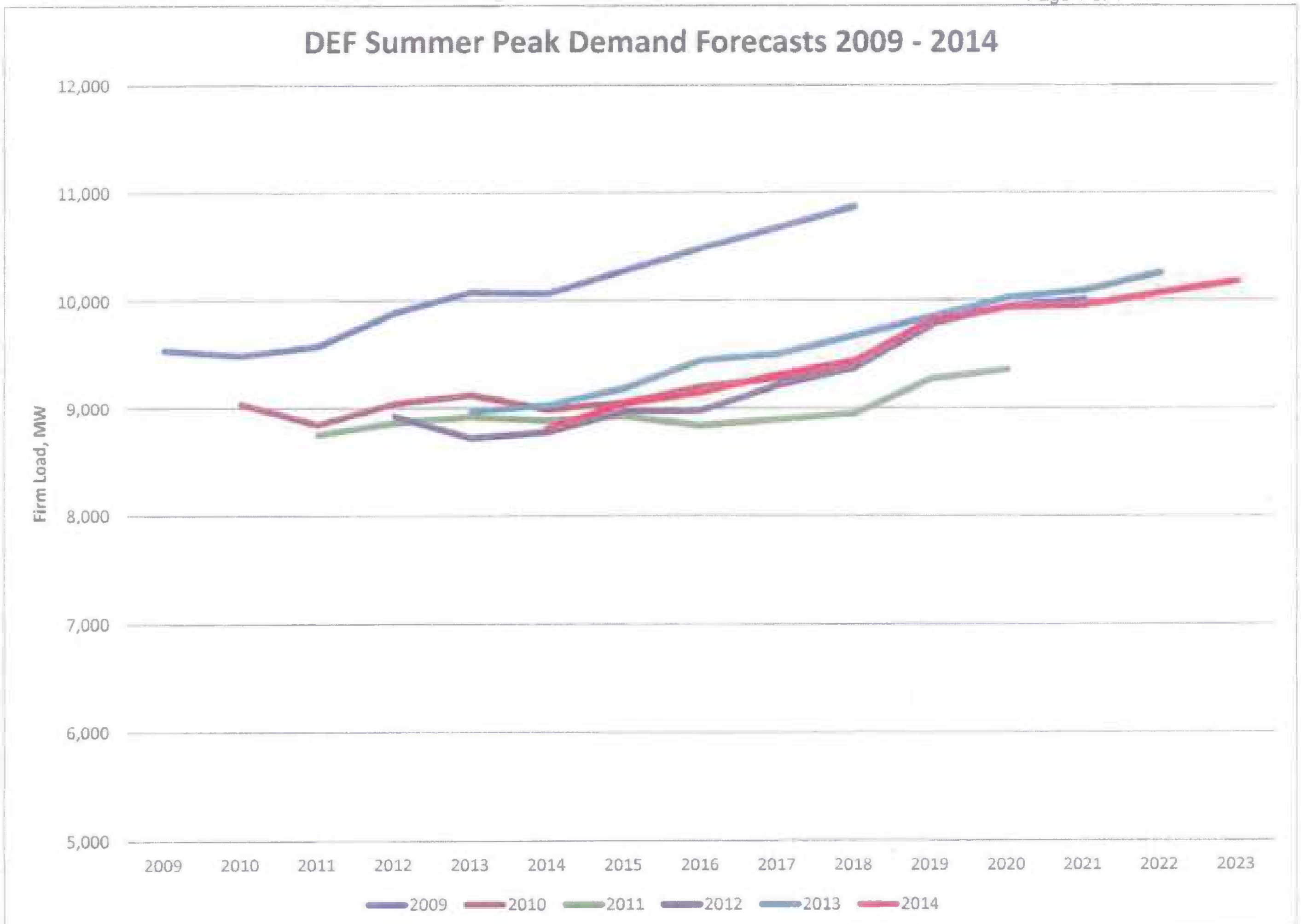

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. 140111-EI Submitted for filing: August 5, 2014

REBUTTAL TESTIMONY
OF JULIE SOLOMON

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

BY DUKE ENERGY FLORIDA, INC.
FPSC DOCKET NO. 140111-EI

REBUTTAL TESTIMONY OF JULIE SOLOMON

I. INTRODUCTION.

Q. Are you the same Julie Solomon that filed Direct Testimony in this docket?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to issues raised in the July 14, 2014 Direct Testimony of Dr. John R. Morris on behalf of NRG Florida L.P. ("NRG"), and Direct Testimony of Dr. David Hunger on behalf of Calpine Construction Finance Company, L.P. ("Calpine"). Each of these testimonies addresses essentially two issues: (i) the potential horizontal market power effects of Duke Energy Florida, Inc. ("DEF" or the "Company") acquiring a generating plant in Florida; and (ii) how FERC might evaluate an application seeking approval for such an acquisition. I address each of these witnesses in turn below, although there is overlap in their testimony with respect to these issues.

Q. Are you sponsoring any exhibits to your Rebuttal Testimony?

A. No.

II. SUMMARY OF REBUTTAL TESTIMONY.

Q. Please briefly summarize your rebuttal of Drs. Morris and Hunger.

A. My key points are summarized here, and then detailed below.

First, neither Dr. Morris nor Dr. Hunger raise any fundamental analytical concerns about the FERC screens I conducted. Their focus is almost exclusively on changing the paradigm of the before (pre-transaction) and after (post-transaction) assumptions and the nature of the transaction itself. In effect, they each develop scenarios for screens that will show absolutely zero effect – *i.e.*, pre- and post-transaction scenarios that yield essentially the same results.

Second, and related to the prior point, both Dr. Morris and Dr. Hunger are testifying about a form of transaction that was not among the acquisition options having been proposed to, or still being considered by, the Company at the time of my Direct Testimony. Specifically, a key element of both of their testimonies is that the evaluation of market power effects and the risks of obtaining FERC approval are changed if the generation alternative being considered consists of a long-term power purchase agreement ("PPA") followed by a generation acquisition, rather than simply an acquisition. Such a proposal was made by Calpine to DEF on June 16, 2014 and revised on July 3, 2014, some 3-5 weeks following the filing of my Direct Testimony on May 27, 2014. While Dr. Morris discusses such an approach, I understand that NRG has not made any formal offer to DEF proposing this approach (although there has been correspondence and discussions between the companies about such an approach).

Third, both witnesses conclude that the risks of obtaining FERC approval are not significant if the form of the transaction changes in the manner described above. Dr.

Hunger concludes that once a long-term (5-year) PPA is entered into and in effect for at least one year, "FERC will almost certainly conclude" that an acquisition would result in no change in market power for DEF. Even if FERC approval were sought as soon as the PPA is executed, Dr. Hunger indicates that FERC precedent suggests this would be acceptable as well. Similarly, Dr. Morris concludes that entering into a long-term PPA and finalizing an acquisition agreement at a later date would lead to a conclusion that there is no change in market power. He concludes that "Duke would need several years remaining on the purchase or tolling agreement" in order for FERC to accept the premise that DEF "controls" the facility pre-transaction. If a transaction involving a long-term PPA that transfers control to DEF combined with a subsequent acquisition is determined to be economic by DEF, I believe that the risks of FERC approval are improved relative to the proposals that are the subject of DEF's original application that I evaluated in my Direct Testimony. Important timing and risk issues potentially remain, however, as I discuss below, particularly as one considers specific, actual structures as opposed to hypothetical/theoretical structures.

Fourth, Dr. Morris raises two issues, distinct from the basic scenario of a long-term PPA followed by an acquisition. One, he seems to argue that the base case (pre-transaction) should assume that DEF has some other additional generation under its control before it acquires additional generation, because this is "the most likely state of competition" without DEF acquiring the Osceola facility. Generally this implies that I understated the amount of Available Economic Capacity that DEF would have pre-transaction before making the decision about what new capacity to add. As a result, when DEF adds new capacity – whether Osceola or something else – the post-transaction market concentration will be identical, or near-identical, to the pre-transaction market concentration such that the HHI change is zero and FERC will approve the transaction. As a general proposition, this argument appears to simply turn the FERC approach on its head – it would suggest for any utility seeking new generation, its status quo already has some form of additional generation in the mix – and I am not aware of such a premise in this form being accepted by FERC. More specifically, Dr. Morris further posits that, in the absence of a deal with DEF, NRG would either contract or sell its plant to another Florida utility or, alternatively, dismantle it and move it outside of Florida, and my analysis should take that into consideration. This approach leads to an analysis that has DEF building new generation and NRG exiting the market in the pre-transaction scenario as compared to a post-transaction scenario in which DEF acquires Osceola. This hypothetical appears, at best, purely theoretical and, at worst, speculative, as Dr. Morris has not presented any evidence in support of these outcomes (nor am I aware of any NRG witness providing such evidence). Two, Dr. Morris argues that there are additional mitigation measures that FERC might accept, citing cost-based offers or temporary transfer of control if the market power concerns were short-lived. Dr. Morris appropriately describes these as hypothetical, and, as noted, there is no firm proposal by NRG underpinning this hypothesis.

Q. How is the remainder of your testimony organized?

A. I address Dr. Hunger's and Dr. Morris' testimony in turn, followed by a summary of my conclusions.

II. RESPONSE TO DR. HUNGER.

Q. What specific issues does Dr. Hunger address in his Direct Testimony?

A. Dr. Hunger focuses on two related transactions under which DEF would acquire Calpine's Osprey Energy Center facility ("Osprey"). In the first transaction, DEF would enter into a 5-year PPA with Calpine to acquire the output of Osprey, with the PPA effectively transferring control from Calpine to DEF. In the subsequent transaction, DEF would acquire Osprey. Dr. Hunger concludes that if FERC authorization is sought a year of more after the PPA takes effect, "FERC will almost certainly conclude that the acquisition will do nothing to change that assignment [of Osprey's output to DEF] and thus will not affect competition…" and, "[c]onsequently FERC should not require a market power analysis." (Hunger at 21:8-15) He further concludes that even if FERC authorization were sought "as soon as the PPA is executed, there is FERC precedent approving this type of structure as well." (Hunger at 21:16-18)

Q. Why did you not analyze this deal structure in your Direct Testimony?

A. Quite simply because that was not one of the scenarios that DEF asked me to analyze. At the time of my Direct Testimony, the only specific proposals being considered by DEF involved the acquisition of generating plants or new builds. Because building new generation does not require FERC approval, I focused on the market power effects of the acquisition of existing generating plants in the DEF balancing authority area ("BAA").

Q. Do you agree with Dr. Hunger's conclusion about the certainty of FERC approval of a PPA plus acquisition proposal?

A. Not entirely. I certainly agree that there is ample FERC precedent that a long-term PPA that is considered to transfer operational control to the buyer is treated in a manner similar to owned capacity. Further, it follows from this that an acquisition of the same type and quantity of generation as is subject to the PPA would indicate no market power concerns (in effect, zero change in market structure or market concentration). On these two points, I agree with Dr. Hunger (as well as Dr. Morris, as discussed below).

That said, it does not necessarily follow that a FERC filing under the specific facts presented here is completely assured of obtaining unconditional FERC approval.

Q. Please explain what is it about the specific fact circumstances proposed here that lead to uncertainty in obtaining FERC approval?

A. A "plain vanilla" filing where an acquisition follows a long-term PPA transferring control should, as Drs. Hunger and Morris assert, have a very high certainty of approval. Setting aside the issue of how long one would need to wait after entering into the PPA to seek such approval, there are two other factors present here that, I believe are untested as to FERC precedent or opinion.

First, it will be clear to FERC in the application (and, in any event, would be otherwise clear to FERC upon review of this docket) that the sole reason for entering into the PPA followed by an acquisition is to facilitate approval under section 203. There is no hiding that fact, and DEF does not intend to do so. To the extent that the transaction was designed specifically to avoid an appearance of market power under section 203, FERC could decide to take that factor into consideration in evaluating the application.

Second, with respect to the Calpine proposal specifically, there are two factors that further complicate the analysis and consideration by FERC. Related to the previous point regarding how FERC would consider a PPA, I note that Calpine's July 3 proposal contemplates a five-year PPA with DEF; however, if FERC does not approve the related acquisition of Osprey, or approves it only with mitigation, the PPA will terminate by the end of 2016. This could cause FERC to conclude it is really a <u>two-year PPA</u>, and further highlight that the PPA is only a vehicle for the ultimate acquisition. This proposal also weakens Dr. Hunger's conclusion that a <u>five-year PPA</u> would not face a significant risk of being disallowed or heavily mitigated by FERC.

Additionally, as I understand from Mr. Borsch, and from Mr. John L. Simpson's testimony on behalf of Calpine, while DEF would enter into a PPA with Calpine for 515 MW of capacity and energy from Osprey (and ultimately would acquire the full 515 MW), only 249 MW of that supply would be deliverable to the DEF BAA under existing firm transmission reservations. The remainder would not be deliverable into the DEF BAA except on a non-firm or short-term, as-available basis (or if, according to Mr. Simpson, additional transmission is available to be purchased from TECO). In the near term, this set of facts would be no different than a "plain vanilla" type filing, as shown in columns (1)-(3) of the table below, namely zero change in MWs controlled in the DEF BAA. However, to the extent DEF would need to make changes to the transmission system (upgrades, operating procedures, redispatch) in order to deliver the full 515 MW of capacity and energy into the DEF BAA, there still could be a change in generation MWs controlled in DEF, as shown in columns (4)-(5) of the table below.

	(1)	(2)	(3)	(4)	(5)
	Pre-Transaction (after PPA)	Post-Transaction (after acquisition)	Change	Post-Transaction (after transmission upgrades)	Change
In DEF BAA	249 MW	249 MW	0	515 MW	+266
In TECO BAA	266 MW	266 MW	0	0 MW	-266
Total	515 MW	515 MW	0	515 MW	0

The associated market power implications under this set of facts have not been considered by Dr. Hunger. He concludes that "the determinative factor in a market power study is what entity has operational control of the generating asset", whether it is zero, 249 MW or 515 MW. (Hunger 18:12-15) He further notes that "FERC strongly favors reliability and enhancements to the power delivery capability of transmission systems" (Hunger 19:12-13). I agree on this point. However, he does not seem to consider the fact that even while FERC looks favorably on transmission investment, in the past it still has required a demonstration through a screen analysis that such transmission expansion would resolve any screen failures such as might occur. This was a prominent element in the FERC order requiring mitigation in the Duke Energy-Progress Energy merger.

While I have not conducted such an analysis, I note that there are many variables affecting the analysis – for example, how much is transmission increased from TECO to DEF, what is the effect on overall import capability into DEF, timing of the changes, etc. If such changes are anticipated, FERC likely would require an analysis that demonstrates a lack of horizontal market power concerns, potentially as part of the original application or a later compliance filing.

These two complicating factors lead me to be more reticent than Dr. Hunger about the certainty of FERC approving the PPA-acquisition combination as proposed by Calpine. Likewise, the first of these factors also affects the risk of obtaining approval for a transaction involving Osceola.

III. RESPONSE TO DR. MORRIS.

Q. What specific issues does Dr. Morris raise in his Direct Testimony?

A. Dr. Morris' testimony raises some similar issues raised by Dr. Hunger with respect to a PPA followed by an acquisition, as already discussed above. He notes that I have not considered a case in which DEF first signs a long-term contract for the NRG Osceola facility and then acquires the facility. (Morris 11:3-6) As I noted earlier, such a transaction was not part of my Direct Testimony because no such proposal had been made at the time (nor am I aware that NRG has now made a formal proposal in that regard), and I was therefore not asked to evaluate such an option. That said, I do not dispute Dr. Morris's analysis on pages 13-14 and Exhibit No.__ (JRM-2) that indicates the HHI change is zero when the base, pre-transaction, case assumes that DEF already controls Osceola under a LT contract and then acquires the plant.

Dr. Morris also notes that I have not considered a case in which DEF acquires the Osceola facility relative to a scenario in which DEF builds its own generation and NRG dismantles and moves the Osceola facility from the DEF BAA. (Morris 11:7-10) At the time of my Direct Testimony, I had no information that there was a plan for NRG to move its facility if it was not acquired by DEF, nor am I aware of any facts to support this hypothetical at the present time, other than Dr. Morris' assertion that "it appears likely that NRG would move the combustion turbines to another location" and that it "appears to be an economic alternative for NRG." (Morris 16:15-21 and 17:1) If Dr. Morris' hypothetical stands up to scrutiny by FERC – which would require far more factual underpinning than presented here – Dr. Morris' analysis in Exhibit No.__ (JRM-3) still suffers from the comparison of a hypothetical pre-transaction scenario to a post-transaction acquisition of Osceola. Whereas, typically, a pre-transaction scenario reflects the status quo, here Dr. Morris' pre-transaction scenario posits a hypothetical, arguably speculative, scenario.

Q. What is Dr. Morris' view about potential mitigation options?

A. Dr. Morris suggests no mitigation would be needed if the "lead time on the acquisition [without an initial PPA] was several years away." (Morris 17:11-12) Of course, the lead time on the acquisition at issue in this proceeding is not several years away.

Dr. Morris, however, acknowledges that an acquisition closing by the end of 2014 – if NRG continues to operate Osceola and there is no PPA – could require mitigation. (Morris 17:13-16) He suggests that mitigation could be limited to Osceola, and effective mitigation options could be (i) "cost-based offers" or (ii) "transferring operational cost [I believe he intended to say "control" rather than "cost"]. (Morris 18:18-20) While Dr. Morris does not explore these options further, I note there are considerations that likely make these mitigation options unworkable. DEF needs the capacity (Osceola or something else) to meet its load-and-reserve margin resource requirements, as discussed by Mr. Borsch. If DEF turns around and "sheds" control over that generation, it may not be able to meet such requirements.

IV. CONCLUSION.

Q. What conclusions do you reach after having reviewed the testimonies of Dr. Hunger and Dr. Morris?

A. First, there is at least one area in which there is little dispute. I agree that there is ample FERC precedent suggesting that the presence of a long-term PPA transferring control to the ultimate buyer can facilitate a subsequent generation acquisition in terms of eliminating market power issues in a FERC application. Timing issues may remain (*e.g.*, how long does the PPA need to be and how long before the parties can seek FERC approval for an acquisition).

Second, there remains a concern under the current circumstances that FERC will consider whether a PPA entered into in order to bypass potential market power problems arising in an acquisition is acceptable. And, with respect to the Calpine Osprey facility, the impact on the FERC screens (and FERC decision making) of new transmission and additional supply deliverable to the DEF BAA in the future must be considered. Thus, even a PPA followed by an acquisition does not fully eliminate the risk of obtaining unconditional FERC approval (*i.e.*, without mitigation).

Third, I am not convinced that Dr. Morris' alternative hypothetical wherein NRG is assumed to be "moving" the Osceola plant out of DEF, will qualify as an acceptable base case scenario in a FERC application. The basic premise of this hypothetical is to assume in the pre-transaction, status quo scenario that (i) DEF will buy or build something; and (ii) NRG will move Osceola out of the market. There would have to be evidence to support the second assumption. And, the first assumption, fully separable from what NRG might do with Osceola, implies that FERC could find that the screens are passed in virtually every instance in which a utility is seeking to buy a new generating plant rather than build new generation. I am unaware of any precedent supporting this notion.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	)))))	DOCKET NO. 140111-EI Submitted for filing: August 21, 2014

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING ERRATA

Duke Energy Florida, Inc. ("DEF") hereby gives notice of filing errata to the May 27, 2014 testimony and exhibits and August 5, 2014 exhibits of Mr. Benjamin M.H. Borsch and to the May 27, 2014 testimony of Julie Solomon as more specifically described below:

- As previously corrected in DEF's Response to NRG's First Set of Interrogatories #89, served on July 7, 2014, in the **May 27, 2014 Direct Testimony of Benjamin M. H. Borsch Page 45, Line 22**, "20-year study period" should be changed to "30-year study period." This was a typo only and had no effect on the analysis. See corrected testimony page attached.

- As referenced in Mr. Borsch's Deposition on August 11, 2014, in **Exhibit No. __(BMHB-3) to Benjamin Borsch's May 27, 2014 Direct Testimony** the "Winter Firm Peak Demand 2014" number should be listed as "8870" versus "8170." This was a typo only and had no effect on the analysis. See corrected Exhibit No. ___(BMHB-3) attached.

- As previously corrected in DEF's Supplemental Response to NRG's First Document Request #8, served on July 11, 2014, in **Exhibit No. __(BMHB-8) to Benjamin Borsch's May 27, 2014 Direct Testimony** there was an error in a formula which transferred model results to the spreadsheet used to create the exhibit. The error caused double counting of some costs for the PPAs which were also accounted for in the fuels totals. The error affected PPA1 and PPA3. This has been corrected and the corrected values were supplied to all parties in response to the NRG Document Request referenced above. The change did not have a material impact on the conclusions. See corrected Exhibit No. ___(BMHB-8) attached.
  - Corrections include:
    - In Column "PPA1" Row "Fuel" the number was corrected from 395 to 394.
    - In Column "PPA1" Row "PPAs" the number was corrected from (567) to (562).
    - In Column "PPA1" Row "Total" the number was corrected from (129) to (126).
    - In Column "PPA3" Row "Fuel" the number was corrected from 45

to 63.
    - In Column "PPA3" Row "PPAs" the number was corrected from (184) to (175).
    - In Column "PPA3" Row "Total" the number was corrected from (155) to (128).
    - In Column "ACQ PPA MIX1" Row "Fuel" the number was corrected from (12) to (11).
    - In Column "ACQ PPA MIX1" Row "PPAs" the number was corrected from (65) to (62).
    - In Column "ACQ PPA MIX1" Row "Total" the number was corrected from (110) to (107).
    - In Column "ACQ PPA MIX2" Row "Fuel" the number was corrected from (260) to (258).
    - In Column "ACQ PPA MIX2" Row "PPAs" the number was corrected from (375) to (372).
    - In Column "ACQ PPA MIX2" Row "Total" the number was corrected from (118) to (117).

- In **Exhibit No. __(BMHB-10) to Benjamin Borsch's May 27, 2014 Direct Testimony** the cost of the 4th Chiller was incorrectly input. The value was $10 million (CPVRR equivalent) less than it should have been. This reduces the cost effectiveness of 4 chillers vs. the 3 chiller base case by $10 million, but it remains cost effective. All comparisons to the alternate bids was done on a 3 chiller basis, so this does not affect any of the differential outcomes to the alternative bids. See corrected Exhibit No. __(BMHB-10) attached.
  - Corrections include:
    - In Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
    - In Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 26 to 16.

- In **Exhibit No. __(BMHB-11) to Benjamin Borsch's May 27, 2014 Direct Testimony** there was an error in the No CO2 price case. The CO2 price was left on for the first two generic CT units following the PPA expirations in the "PPA1" and "ACQ PPA MIX 1" cases. As a result, these cases were more costly because they included CO2 allowance costs for those units. These costs also affected the dispatch which resulted in a shift in other costs (Fuel, VOM, etc.). This error did not affect the rank order of the results or materially affect the conclusions. See corrected Exhibit No. ___(BMHB-11) attached. This update to Exhibit No. __ (BMHB-11) also incorporates the change in the capital cost of the 4th Hines Chiller discussed in reference to Exhibit No. ___(BMHB-10).
  - Corrections include:
    - In Table "High Gas" in Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
    - In Table "High Gas" in Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 41 to 31.

- In Table "No CO2" in Column "AQCPPA MIX1" Row "Fuel" the number was corrected from 23 to 28.
- In Table "No CO2" in Column "AQCPPA MIX1" Row "Emissions" the number was corrected from (13) to 1.
- In Table "No CO2" in Column "AQCPPA MIX1" Row "Variable Costs" the number was corrected from (9) to (7).
- In Table "No CO2" in Column "AQCPPA MIX1" Row "PPAs" the number was corrected from (117) to (116).
- In Table "No CO2" in Column "AQCPPA MIX1" Row "Total" the number was corrected from (170) to (149).
- In Table "No CO2" in Column "PPA1" Row "Fuel" the number was corrected from 205 to 210.
- In Table "No CO2" in Column "PPA1" Row "Emissions" the number was corrected from (12) to 3.
- In Table "No CO2" in Column "PPA1" Row "Variable Costs" the number was corrected from 3 to 5.
- In Table "No CO2" in Column "PPA1" Row "PPAs" the number was corrected from (311) to (309).
- In Table "No CO2" in Column "PPA1" Row "Total" the number was corrected from (161) to (137).
- In Table "No CO2", in Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
- In Table "No CO2", in Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 14 to 4.

- As referenced in Mr. Borsch's Deposition on August 11, 2014, the label in the top right corner for **Exhibit No. __(BMBHB-15) to Benjamin Borsch's August 5, 2014 Rebuttal Testimony** contained typos and should be labeled as "Exhibit No.__(BMHB-15)."

- As previously corrected in DEF's Response to Staff's First Set of Interrogatories #40a, served on July 15, 2014, in the **May 27, 2014 Direct Testimony of Julie Solomon Page 9, Line 14** the words "these" and "or" should have been deleted. See corrected testimony page attached.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic mail this 21st day of August, 2014.

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by increasing the total supply of generation in the market. This means the Company must build additional transmission facilities to expand the transmission import capability. The Company cannot rely on currently planned transmission system facility upgrades for this mitigation. The additional transmission must be net new facilities to the DEF system.

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

The best generation facility acquisition proposal was only marginally more cost-effective on a CPVRR basis over the ~~20-year~~ 30 year study period than the Company's self-build base generation plan. This marginal benefit does not

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Corrected Exhibit No. ____ (BMHB-3)
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DEF's Near Term Summer And Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy Requirements (GWH)
	Winter	Summer	
2014	8,8 70	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

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

Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self Build									
$M 2013	PPA1	PPA2	PPA3	ACQ2	ACQ1	ACQ PPA MIX1	ACQ PPA MIX2	ACQ3	ACQ4
Capital Costs	37	90	90	(49)	204	101	101	23	(35)
Fuel	394	141	63	(50)	16	(11)	258	7	(3)
Emissions	19	23	19	(71)	(47)	(3)	15	13	1
Variable Costs	19	(4)	(9)	113	34	(4)	10	(0)	1
Fixed Costs	(36)	(122)	(122)	(148)	(162)	(129)	(129)	(310)	(351)
PPAs	(562)	(270)	(175)	44	10	(62)	(372)	9	2
Cogens	(1)	5	6	(36)	(9)	0	(2)	0	1
Emergency Energy	4	2	0	4	2	2	2	3	(2)
Total	(126)	(136)	(128)	(193)	49	(107)	(117)	(255)	(386)

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

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build				
$M 2014	Acquisition - PPA Mix 1	PPA 1	Self Build No Hines Chillers	Self Build plus Hines 1 Chillers
Capital Costs	88	83	52	(43)
Fuel	50	227	(36)	68
Emissions	16	29	(24)	19
Variable Costs	(9)	2	13	(2)
Fixed Costs	(141)	(129)	(7)	5
PPAs	(143)	(332)	(27)	(29)
Cogens	1	3	(0)	(2)
Emergency Energy	(1)	(1)	3	1
Total	(139)	(118)	(26)	16

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

High Gas			
Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self			
$M 2014	ACQ PPA MIX1	PPA1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(43)
Fuel	35	267	53
Emissions	15	29	21
Variable Costs	(10)	2	(4)
Fixed Costs	(141)	(129)	5
PPAs	(123)	(364)	(1)
Cogens	1	3	(1)
Emergency Energy	(1)	(1)	1
Total	(138)	(110)	31

No CO2			
Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self			
$M 2014	AQC PPA MIX1	PPA1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(43)
Fuel	28	210	46
Emissions	1	3	(1)
Variable Costs	(7)	5	(2)
Fixed Costs	(141)	(129)	5
PPAs	(116)	(309)	(2)
Cogens	(0)	1	(1)
Emergency Energy	(1)	(1)	1
Total	(149)	(137)	4

Passing the FERC Competitive Analysis Screen typically leads to a conclusion that a transaction is unlikely to present competitive problems. If the Competitive Analysis Screen is "failed", i.e. the changes in market concentration exceed the allowed level, the proposed merger or acquisition is deemed likely to have an adverse impact on competition and FERC will look more closely at the transaction before making its final determination. As FERC has stated: "When there is a screen failure, applicants must provide evidence of relevant market conditions that indicate a lack of a competitive problem or they should propose mitigation." In re: Revised Filing Requirements under Part 33 of the Commission's Regulations, Order 642 FERC Stats. & Regs., ¶31,11, at page 62 (2000).

Evidence of relevant market conditions that may indicate a lack of a competitive problem include "demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved." (Id.). No facts such as ~~these~~ have been relied on by FERC in previous orders ~~or~~ have been identified in the acquisitions at issue and, as a result, the FERC inquiry likely would be on any proposed mitigation.

Q. Why did FERC adopt the Competitive Analysis Screen?

A. FERC adopted its merger filing requirements, including the Competitive Analysis Screen, to provide regulatory certainty to the industry in obtaining approval for mergers or generation transactions. The Competitive Analysis Screen is intended to provide a conservative standard to allow parties to identify mergers or generation facility acquisitions that are unlikely to present competitive problems.

Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self Build			
$M 2015	Osprey vs Self Build - Mid Fuel - No CO2	Osprey vs Self Build - Mid Fuel - With CO2	Osprey vs Self Build - High Fuel - With CO2
Capital Costs	(11)	(11)	(11)
Fuel	102	83	127
Emissions	1	133	127
Variable Costs	72	63	61
Fixed Costs	(136)	(136)	(136)
PPAs	(56)	(61)	(77)
Cogens	5	(9)	(8)
Emergency Energy	(1)	(1)	(1)
Positive - Osprey Acquisition Savings	(24)	61	81

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				Osprey		Suwannee CTs	
Year	Summer Firm Peak Demand	Installed Capacity without New Additions	Reserve Margin	Installed Capacity	Reserve Margin	Installed Capacity	Reserve Margin
2014	8,812	11,024	25.1%	11,024	25.1%	11,024	25.1%
2015	9,042	11,235	24.3%	11,235	24.3%	11,235	24.3%
2016	9,149	11,231	22.8%	11,231	22.8%	11,231	22.8%
2017	9,307	10,985	18.0%	11,222	20.6%	11,230	20.7%
2018	9,439	10,994	16.5%	11,281	19.5%	11,310	19.8%
2019	9,813	11,814	20.4%	12,051	22.8%	12,130	23.6%
2020	9,935	11,709	17.9%	12,284	23.6%	12,025	21.0%
2021	9,952	11,284	13.4%	11,959	20.2%	12,393	24.5%