BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

PETITION FOR DETERMINATION OF NEED FOR CITRUS COUNTY COMBINED CYCLE POWER PLANT, BY DUKE ENERGY FLORIDA, INC. — DOCKET NO. 140110-EI

PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018, BY DUKE ENERGY FLORIDA, INC. — DOCKET NO. 140111-EI

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VOLUME 3
Pages 262 through 377

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, August 26, 2014

TIME: Commenced at 2:00 p.m.
Concluded at 4:50 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

INDEX TO EXHIBITS

NO.	RECEIVED
35	302

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

MR. WALLS: We call Mr. Alan Taylor.

Whereupon,

ALAN TAYLOR

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Taylor, will you please introduce yourself to the Commission and provide your business address?

A My name is Alan Taylor. My address is 821 15th Street, Boulder, Colorado, 80302.

Q And, Mr. Taylor, have you been sworn in as a witness?

A Yes, I have.

Q And who do you work -- well, you already told us who you work for. What is your position?

A I work for Sedway Consulting, and I am the President of the firm.

Q Okay. Do you have your prefiled direct testimony with you today?

A Yes, I do.

Q Do you have any changes to make to your prefiled direct testimony?

A I do not.

Q If I asked you the same questions in your prefiled direct testimony today, would you give the same answers that are in your prefiled testimony?

A Yes, I would.

MR. WALLS: And we request that the prefiled direct testimony be entered into the record as if it were read here today.

CHAIRMAN GRAHAM: We will enter Mr. Taylor's prefiled direct testimony into the record as though read.

IN RE: PETITION FOR DETERMINATION OF NEED FOR CITRUS COUNTY COMBINED CYCLE POWER PLANT

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. _________

DIRECT TESTIMONY OF ALAN S. TAYLOR

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Alan Taylor. My business address is 821 15th Street, Boulder, Colorado 80302.

Q. By whom are you employed and in what capacity?

A. I am President of Sedway Consulting, Inc. ("Sedway Consulting").

Q. Please describe your duties and responsibilities in that position.

A. I perform consulting engagements in which I assist utilities, regulators, and customers with the challenges that they may face in today's dynamic electricity marketplace. My area of specialization is in the provision of independent evaluation services in power supply solicitations and in the associated economic and financial analysis of power supply options.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Science Degree in energy engineering from the Massachusetts Institute of Technology and a Masters of Business Administration from the Haas School of Business at the University of California, Berkeley, where I specialized in finance.

I have worked in the utility planning and operations area for 25 years, predominantly as a consultant specializing in integrated resource planning, competitive bidding analysis, utility industry restructuring, market price forecasting, and asset valuation. I have testified before state commissions in proceedings involving resource solicitations, environmental surcharges, and fuel adjustment clauses.

I began my career at Baltimore Gas & Electric Company ("BG&E"), where I performed efficiency and environmental compliance testing on the utility system's power plants. I subsequently worked for five years as a senior consultant at Energy Management Associates ("EMA", now New Energy Associates), training and assisting over two dozen utilities in their use of EMA's operational and strategic planning models, PROMOD III and PROSCREEN II. During my graduate studies, I was employed by Pacific Gas & Electric Company ("PG&E"), where I analyzed the utility's proposed demand side management ("DSM") incentive ratemaking mechanism, and by Lawrence Berkeley Laboratory ("LBL"), where I evaluated utility regulatory policies surrounding the development of brownfield generation sites.

Subsequently, I worked at PHB Hagler Bailly (and its predecessor firms) for ten years, serving as a vice president in the firm's Global Economic Business Services practice and as a senior member of the Wholesale Energy Markets practice of PA Consulting Group, when that firm acquired PHB Hagler Bailly in 2000. In 2001, I founded Sedway Consulting, Inc. and have continued to specialize in economic analyses associated with electricity wholesale markets. Since the founding of Sedway Consulting, I have provided independent evaluation services in over two dozen electric utility conventional and renewable resource solicitations.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. Sedway Consulting was retained by Duke Energy Florida, Inc. ("DEF" or the "Company") to provide independent monitoring and evaluation services in the utility's 2013 solicitation for competitive power supplies. As the principal consultant on the project, I helped with the development of the Request for Proposals ("RFP") and associated website, reviewed DEF's solicitation process, and performed a parallel and independent economic evaluation of both DEF's Next Planned Generating Unit ("NPGU") and the proposals that were received by DEF in response to the utility's solicitation. Ultimately, I concluded that DEF's NPGU – the Citrus County combined-cycle ("CC") facility described in DEF's RFP – represented the most cost-effective resource for meeting DEF's resource needs for 2018. This resource will entail two 820 MW (summer capacity) phases with in-service dates of May 1, 2018, and December 1, 2018, for a total installed capacity of 1,640 MW by the end of 2018. DEF's RFP sought power supply alternatives for this 2018 time-frame and thus is referred throughout my testimony and attachments as the 2018 RFP.

The purpose of my testimony is to describe my role as an independent monitor/evaluator and present my findings. I will discuss the process and tools that I used to conduct Sedway Consulting's independent economic evaluation. Based on the results of my independent evaluation, I concluded that DEF's Citrus County CC resource is more cost-effective than the proposed power purchase agreement ("PPA") and asset sale alternatives that were submitted in DEF's resource solicitation.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit No. __ (AST-1) consisting of two documents, which are attached to my direct testimony:

Document No. 1	Resume of Alan S. Taylor
Document No. 2	Sedway Consulting's Independent Evaluation Report

III. INDEPENDENT MONITOR/EVALUATOR ACTIVITIES.

Q. Please describe the role you performed as an independent monitor/evaluator in DEF's 2018 RFP project.

A. As the independent monitor/evaluator in DEF's 2018 RFP, I reviewed DEF's 2013 Ten-Year Site Plan, the RFP and associated website prior to the solicitation's launch, and the utility's modeling processes pertaining to its use of EPM, DEF's detailed production cost model. I attended the October 2, 2013 Pre-

Issuance Meeting and the October 18, 2013 Bidders Conference, both in Tampa. Throughout the process, I monitored all email exchanges and conference calls between DEF and potential or actual bidders. Before receiving the proposals, I requested that DEF run its detailed production cost model and provide production cost results that I could use to calibrate Sedway Consulting's resource evaluation model. Per the instructions in the RFP, I was sent electronic copies of all proposals directly from the bidders on or about the Proposal Due Date (December 9, 2013) and evaluated the economic, operational, and pricing information from each proposal. DEF conferred with me on a number of issues relating to proposal RFP-noncompliance decisions, interpretation of proposal information, clarification requests, and economic evaluation assumptions. Regarding RFP-noncompliance decisions, there were proposals that did not meet all of the RFP's threshold requirements and technical criteria. DEF and Sedway Consulting decided to set aside these matters, move ahead with the evaluation of those proposals, and reconsider the issues in a qualitative assessment later if necessary. As the evaluation progressed, DEF and I discussed appropriate courses of action and modeling assumptions. Using Sedway Consulting's Response Surface Model ("RSM"), I evaluated DEF's NPGU and each submitted proposal and assessed their overall costs. I compared Sedway Consulting's ranking and results with those of DEF to confirm consistency of assumptions and concurrence of conclusions, and I documented the entire process in an independent evaluation report.

Q. You stated that you were involved in the development of the RFP and associated website. What did your involvement entail?

A. As the independent evaluator, I reviewed draft versions of the RFP document and website, participated in several discussions by phone, and was given the opportunity to provide my input and suggestions for improving the RFP and associated website. As an example, DEF had decided to conduct its 2018 RFP through the use of a web platform called PowerAdvocate and suggested that Sedway Consulting simply download all proposal submissions that were updated to this platform. In other power supply solicitations, Sedway Consulting has conducted a bid opening process where it has received and retained materials directly from bidders without relying on any intermediary and felt that the integrity of the independent monitor/evaluator process was enhanced by this. DEF agreed to change its RFP and website information to instruct all bidders to send electronic copies of all proposal materials on a flashdrive directly to Sedway Consulting following their uploading of such materials to the web platform.

Q. Do you believe that DEF's RFP was a reasonable document for soliciting proposals?

A. Yes. As one who has developed over a dozen such utility resource RFPs, I believe that DEF's RFP struck a good balance between being sufficiently detailed without being burdensome on the respondent. With its RFP, DEF released an Attachment A – Key Terms, Conditions and Definitions document that provided bidders with a clear understanding of the general business arrangement that DEF contemplated.

Q. Do you believe that DEF's evaluation process was conducted fairly?

A. Yes. The proposals and DEF's NPGU were evaluated on an equal footing, with consistent assumptions applied to all resource options.

IV. DESCRIPTION OF SEDWAY CONSULTING MODEL.

Q. Please describe Sedway Consulting's RSM model and its use in DEF's resource solicitation.

A. The RSM is a spreadsheet model that I have used in dozens of solicitations around the country. It is a relatively straightforward tool that allows one to independently assess the cost impacts of different generating or purchase resources for a utility's supply portfolio. Most of the evaluation analytics in the RSM involve calculations that are based entirely on my input of proposal costs and characteristics. A small part of the model examines system production cost impacts and needs to be calibrated to simulate a specific utility's system. In the case of the DEF solicitation, in the weeks prior to the proposal opening, I requested that DEF execute specific sets of runs with its detailed production cost model. With the results of these runs, I was able to calibrate the RSM to approximate the production cost results that DEF's EPM detailed production cost model would produce in a subsequent evaluation of any proposals or self-build options that DEF might receive. Thus, I would not have to rely on DEF's modeling of a proposal or self-build option; instead, I would be able to insert my own inputs into my own model and independently evaluate the economic impact of any particular resource. In short, the RSM provides an independent assessment to help ensure against the inadvertent introduction of significant mistakes that could cause the evaluation team to reach the wrong conclusions.

Q. How is the RSM an independent analytical tool if it is based on initial EPM results?

A. As I noted above, most of the calculations performed by the RSM are not based on EPM results in any way. There are two main categories of costs that are evaluated in a resource solicitation: fixed costs and variable costs. The costs in the first category – the fixed costs of a proposal – are calculated entirely separately in the RSM, with no reliance on the EPM model for these calculations. The second category – variable costs – has two parts: (1) the calculation of a resource's variable dispatch rates and, (2) the impact that a resource with such variable rates is likely to have on DEF's total system production costs. As with the fixed costs, a proposal's variable dispatch rates are calculated entirely separately in the RSM, with no basis or reliance on the EPM model. It is only in the final subcategory – the impact that a resource is likely to have on system production costs – that the RSM has any reliance on calibrated results from EPM.

Q. Please elaborate on that area of calculations where the RSM is affected by the EPM calibration runs.

A. This is the area of system production costs. These costs represent the total fuel, variable operation and maintenance (O&M), emission, and purchased power energy costs that DEF incurs in serving its customers' load. Given DEF's load forecast, the existing DEF supply portfolio (i.e., all current generating facilities and purchase power contracts), and many specific assumptions about future resources and fuel costs, EPM simulates the dispatch of DEF's system and forecasts total production costs for each month of each year of the study period. At the outset of the solicitation project, the RSM was populated with monthly system production cost results that were created by the EPM calibration runs.

Q. What did the RSM do with this production cost information?

A. Once incorporated into the RSM, the production cost information allowed the RSM to answer the question: How much money (in monthly total production costs) is DEF likely to save if it acquires a proposed resource, relative to a reference resource? The use of a reference resource simply allowed a consistent point of comparison for evaluating all proposals and DEF's self-build options. As a reference resource, I used a hypothetical gas-fired resource with a very high variable dispatch rate associated with a heat rate of 15,000 Btu/kWh. In fact, I could have picked any variable dispatch or heat rate for the reference resource and obtained the same relative ranking of proposals out of the RSM. The cost of the reference resource has no impact on the relative results – it is merely a consistent reference point.

Q. Can you provide a numerical example that shows how the RSM works?

A. Certainly. Assume that a utility has a one-year resource need of 500 MW and must select one of the two following proposals:

	<u>Proposal A</u>	**<u>Proposal B</u>**
Capacity:	500 MW	500 MW
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Price:	$40/MWh	$60/MWh

For both proposals, the RSM has already calculated the fixed costs (and represented them in the capacity price) and the variable costs (and represented them in the energy price). Proposal A is more expensive in terms of fixed costs, but Proposal B is more expensive on an energy cost basis. The RSM calculates the final piece of the economic analysis – the different impacts on system production costs – to determine which proposal is less expensive in a total sense for the utility system as a whole.

Assume that the 15,000 Btu/kWh reference unit has a variable cost of $90/MWh and that the RSM has been calibrated and populated with the following production cost information:

For a 500 MW proxy resource, the utility's one-year total system production costs are:

$900 million for a $90/MWh energy price reference resource
$894 million for a $60/MWh energy price resource (Proposal B)
$876 million for a $40/MWh energy price resource (Proposal A)

Thus, the energy savings (relative to the selection of a $90/MWh reference resource) are $24 million for Proposal A with its $40/MWh energy price and $6 million for Proposal B with its $60/MWh energy price. In its proposal ranking process, the RSM converts all production cost savings into a $/kW-month equivalent value so that the savings can be deducted from the capacity price to yield a final net cost (in $/kW-month) for each proposal. Converting the energy savings in this numerical example into $/kW-month equivalent values yields the following:

$24 million / (500 MW * 12 months) = $4.00/kW-month
$6 million / (500 MW * 12 months) = $1.00/kW-month

The RSM calculates the net cost of both proposals by subtracting the energy cost savings from the fixed costs:

	Proposal A	**Proposal B**
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Cost Savings:	$4.00/kW-month	$1.00/kW-month
Net Cost:	$5.00/kW-month	$4.50/kW-month

Proposal B is less expensive. This can be confirmed through a total cost analysis as well:

Proposal A will require total capacity payments of $54 million (= 500 MW x $9.00/kW-month x 12 months), and Proposal B will require $33 million (= 500 MW x $5.50/kW-month x 12 months). Thus, Proposal A has fixed costs that are $21 million more than Proposal B.

Proposal A will provide $18 million more in energy cost savings (= $24 million - $6 million); however, this is not enough to warrant paying $21 million more in fixed costs. Therefore, Proposal B is the less expensive alternative.

Note that the RSM is described in more detail in the independent evaluation report that is attached to my testimony as Document Number 2 of my Exhibit No. ___(AST-1).

Q. With that understanding of the RSM process, what did you do to calibrate the RSM to EPM?

A. I reviewed the production cost information that DEF provided at the start of the project and confirmed that the production costs were, for the most part, exhibiting smooth, correct trends (i.e., they were increasing where they should be increasing and declining where they should be declining). Having verified that the RSM production cost values were "smooth," I was confident that inputting variable cost parameters into the models for similar proposals would yield similar production cost results. Although the RSM is not a detailed model and could not simulate DEF's production costs with EPM's accuracy, in the end (after accounting for future portfolio composition and future unit revenue requirement methodology differences), the independent RSM evaluation results tracked EPM's results reasonably well.

Q. Once the RSM was calibrated, what was the next step?

A. I was ready to receive and evaluate proposals. Bidders (and DEF's NPGU team) had been instructed to directly send me electronic versions of all proposals by December 10, 2013, and indeed all participants in the RFP did. I read each proposal and participated in discussions with DEF about interpreting the proposals, identifying areas requiring clarification, and assessing each proposal's compliance with the RFP's Minimum Requirements. DEF communicated with proposers to seek clarification and corrections to uncertain areas of the proposals, copying me on all email correspondence and encouraging bidders to do the same.

I incorporated pricing and operational information from each proposal into the RSM. Such information included contract commencement and expiration dates, summer and winter capacity, capacity pricing, heat rates, fuel supply assumptions, variable O&M charges, start-up costs, expected forced outage hours, and expected planned outage hours. Most of this information was directly inputted into the RSM. After the initial part of the evaluation, DEF provided Sedway Consulting with its own modeling results so that Sedway Consulting could cross-check all key modeling assumptions and outputs and ensure consistency with the information in the RSM.

Q. Were there any costs that were considered in Sedway Consulting's analysis that were not predefined through the EPM/RSM calibration process described above or were not part of the actual proposals' pricing?

A. Yes, as described in the attached Independent Evaluation Report, there were two categories of costs that could not be predicted prior to the receipt of proposals or appropriately characterized in the pricing structure of proposals – 1) cost estimates for transmission network upgrades that might be required to accommodate a proposed resource or combination of resources, and 2) cost estimates for firm gas transportation requirements for gas-fired resources. Both of these cost categories were highly dependent on the location of projects, their point of electrical interconnection, and their natural gas pipeline supply considerations.

Q. How were these cost estimates developed?

A. In both cases, DEF's subject area experts provided these cost estimates after being provided pertinent details about the proposed resources.

Q. Were you in a position to independently verify these estimates?

A. No. Sedway Consulting does not have the transmission models or in-depth knowledge of Florida's current or future electric or natural gas infrastructure to develop or verify the estimates of DEF's subject area experts. However, I found them to be fairly balanced and consistent from a $/kW standpoint and do not believe that any bidder was inappropriately advantaged or disadvantaged by these estimates. I studied the estimates to see if anything was out of line and concluded that they did not appear to be biased. In addition, I was free to use or modify the estimated costs in any way I deemed appropriate – and indeed did so, in line with evaluation processes that Sedway Consulting has employed in other resource solicitations.

Q. Were there any other DEF estimates that were used in your analysis that were not locked down prior to the receipt of proposals?

A. Yes, in a sense. Sedway Consulting and DEF had discussed and locked down assumptions about generic resources that would be modeled at the end of any PPA contract periods to allow for a consistent evaluation of all proposals over the complete study period (2015-2053). Those assumptions were based on DEF's 2013 Ten-Year Site Plan and were shared with the bidding community through the RFP and a Question & Answers ("Q&A") forum prior to the submission of proposals. During the evaluation, Sedway Consulting and DEF re-examined these generic resource "back-fill" assumptions and decided to make adjustments that would better represent the operating characteristics and costs associated with such back-fill resources during the period that they would be in service. Specifically, the assumptions were improved to recognize better heat rates (and associated lower firm gas transportation costs) and lower transmission costs for these back-fill resources. These adjustments improved the economics of all PPAs because they added a better back-fill resource than had been depicted in the RFP and Q&As. In fact, the economics of the back-fill resource were better than those of DEF's NPGU (which was based on standard current CC technology).

Q. So you do not believe that these adjustments to the back-fill resource's assumptions were in any way biased against the outside proposals?

A. No. In fact, as noted above and described in more detail in Sedway Consulting's independent evaluation report that is attached as Document No. 2 of my Exhibit No. AST-1, the adjustments improved the 35-year economics of the outside PPA proposals. All of these proposals would have ranked lower (i.e., less favorable) had the evaluation relied on the original back-fill assumptions.

V. SEDWAY CONSULTING'S FINDINGS AND RESULTS.

Q. What were the results of Sedway Consulting's RSM analysis?

A. Using the RSM, Sedway Consulting was able to compare the economics of DEF's NPGU and each of the proposed resource options. That comparison entailed a calculation of the net present value of each option from 2015 through 2053 and accounted for 1) generic resources that would need to "fill in" behind options that expired before 2053 and 2) generic resources that would need to supplement the capacity of each proposed option or combination of options to ensure that all portfolios were the same size in MWs. DEF's NPGU was found to be $282 million (cumulative present value of revenue requirements – "CPVRR") less expensive than the next best portfolio of alternatives. The results, ranking of resources and additional scenarios are described in detail in Sedway Consulting's independent evaluation report that is attached as Document No. 2 of my Exhibit No. __ (AST-1).

Q. What do you conclude about DEF's solicitation?

A. I conclude that DEF's NPGU is the most cost-effective resource for meeting DEF's 2018 capacity needs and concur with DEF's decision to move forward with that project. The solicitation process yielded the best results for DEF's customers while treating proposers fairly. The RFP was sufficiently detailed to provide necessary information to proposers. The economic evaluation methodology and assumptions were appropriate and unbiased, and the independent evaluation procedures provided a cross-check of DEF's proposal representation in EPM and confirmed DEF's conclusions. Finally, I conclude that DEF's NPGU is at least $282 million CPVRR less expensive than the next best portfolio of alternatives.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BY MR. WALLS:

Q Mr. Taylor, do you have a summary of your prefiled direct testimony?

A Yes, do I.

Q Can you please provide that to the Commission at this time?

A Certainly.

Mr. Chairman, Commissioners. I am the President of Sedway Consulting, a firm that specializes in independent -- in providing independent evaluation services and utility power supply solicitations around the country. In fact, I have sat in this chair on a number occasions supporting various solicitation processes and results here in Florida. But I and my team have overseen solicitations -- dozens of solicitations around the country. I have evaluated well over 1,000 power supply proposals and helped negotiate over 100 power supply agreements.

Sedway Consulting was obtained by Duke Energy Florida approximately this time last year to provide independent monitoring and evaluation services in their then upcoming solicitation for power supplies in the 2018 timeframe. And as the principle consultant involved in the project, I helped review and oversee the development of the RFP itself, review the actual evaluation processes that would be undertaken by DEF and Sedway Consulting, and provide a parallel and economic -- independent economic evaluation of any proposals that might be received in response to the solicitation as well as Duke's Next Planned Generating Unit, which was the Citrus County facility. I believe that DEF's RFP was reasonable and an appropriate document for the solicitation of proposals, and that their evaluation process was conducted fairly.

Using Sedway Consulting proprietary Response Surface Model, I did perform this independent evaluation of the NPGU and all of the proposals that were received in response to the solicitation. And I believe that the Citrus County Combined Cycle facility was ultimately the most cost-effective resource in meeting DEF's 2018 resource need.

I am available to answer any questions that you may have. And this concludes the summary of my direct testimony.

Thank you.

MR. WALLS: We tender Mr. Taylor for cross-examination.

CHAIRMAN GRAHAM: Mr. Taylor, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Mr. Rehwinkle.

MR. REHWINKLE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. REHWINKLE:

Q Good afternoon, Mr. Taylor.

A Good afternoon.

Q Do you -- Charles Rehwinkle, with the Office of Public Counsel.

Do you have any information regarding the Calpine deal that was announced today?

A I do not.

Q So you can't say whether the Calpine deal would have any impact on your testimony?

A I cannot.

Q And likewise, you could not testify to the Commission today whether there would be any impact of the Calpine deal on the proposed 2018 need for the Citrus County Combined Cycle Unit, right?

A I really cannot, in the sense that my testimony is focused entirely on the RFP process and what was known as we received proposals back in the December timeframe of 2013.

Q Thank you.

MR. REHWINKLE: Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Calpine.

MR. WRIGHT: No questions, Mr. Chairman.

Thank you.

CHAIRMAN GRAHAM: Shady Hill.

MS. SHELLEY: No questions. Thank you.

CHAIRMAN GRAHAM: PCS.

MR. BREW: No questions. Thank you.

CHAIRMAN GRAHAM: NRG.

MS. RULE: Thank you. No questions.

CHAIRMAN GRAHAM: Mr. Moyle.

CROSS EXAMINATION

BY MR. MOYLE:

Q In your testimony, you say you developed over a dozen utility resource RFPs?

A Correct.

Q Have those been for utilities in and out of Florida, or just Florida utilities or --

A No, all across the country.

Q Have you been involved in other ones in Florida?

A Yes, I have.

Q For FPL?

A For the Florida Power & Light, for Seminole, for Tampa electric and for the old legacy Progress Energy many years ago.

Q And you are familiar with the bid rule that Florida has, is that right? Did you -- is that right?

A Yes, I am.

Q And did you consider that as part of your evaluation to check and see whether the utility was compliant with the bid rule?

A Yes.

Q Okay. And in terms of your independent evaluation, were you the person that made the judgment and said, okay, I got all of these proposals in, here is the one I think is best? I mean, you were contracted to be the neutral third-party that would make a decision about who would win the RFP?

A No. I would say in none of the solicitations that I oversee around the country am I, as an outside third-party, the decision-maker in exactly what moves forward. Obviously, the utility that is procuring the power supply is -- ultimately bears full responsibility and needs to put forth the plan before its regulatory commission and seek cost recovery of that plan.

So I am not the one with the power to say yes or no. I am in a position to review the results and come up with my own independent position, and to provide that information to whoever wishes to hear.

Q So you have never been involved in an RFP, or design of an RFP where an independent third-party, say like this commission or, you know, the Department of

Management Services, or the at the federal level, the general accounting group where they were making the decision; it's always been RFPs for utilities and utilities make the decision?

A Correct. Yes. It's -- in my experience, in all power supply solicitations for electric supplies, the purchasing entity, the utility, is the one that bears full responsibility for the outcome of the solicitation and, therefore, needs to be in that position to make the final decision.

Q And you don't need to explain, but just -- unless you feel compelled to, but we are trying to move things along. But do you think that is a fair setup, where the utility which has a bid that's being considered, so it's a participant, is also the judge in an RFP process?

A I think that's largely --

Q Just yes or no?

A Yes. I think that that's a very good reason for having an independent evaluator be involved in the process, to monitor and parallel the evaluation and be able to provide the Commission and Commission staff with any information they might need as far as my own opinion and my firm's conclusions there.

Q Have you ever disagreed with any of your

clients and said, no, I think you should make the other selection because the information provided by a nonutility entity is a better deal?

A Yes, I have.

Q Have you ever done it in Florida?

A Certainly not by the end of a solicitation process. And I would say that in every instance where I have been an independent evaluator, there have been disagreements along the way, and I have argued for particular positions that may have gone against where the utility's management at the time was tending to go with their thinking. By the end of the process, I have been persuasive enough that they have come around to my suggestions.

As far as Florida, nothing comes to mind where there was any disagreement by the end of the line, and I can't even remember on an intermediate basis where there may have been. But certainly in my career, there have been instances where I have felt like the utility evaluation team was going off track, and I was recommending to senior management a different tact and they adopted my position.

Q And you are aware in Florida there has never been a third-party award pursuant to the bid rule and competitive procurement process, correct?

A I believe that's correct, yes.

Q Okay. One final question. You said in your testimony that you are involved in utility industry restructuring?

A Yes.

Q Was that when markets were moving to ISOs or RTOs?

A Correct.

Q And would you agree that from a competitive standpoint, that that arrangement, an RTO or an ISO, where people are bidding in a realtime basis, is a more rigorous type process for pricing than this RFP process in this proceeding; correct?

A I don't know that I necessarily would agree. I think the jury is still out on some of that. Certainly, I am thinking back to the experience that California had in 2000 and 2001, where they were 100 percent dependent upon a market-based exchange that obviously led to a major collapse in the markets and bankruptcies and the lights going out.

California adopted then an RFP process where they ensured that reliability was met with the utility -- the utilities having the responsibility to actually go out and procure new power supplies for the entire customer base; not just their customers, but also direct access and community choice. So I think that a hybrid system between a pure ISO market and an RFP kind of process may actually work best.

Q You are in Boulder?

A Correct.

Q Do you get your power through an ISO or an RTO?

A I get it from a local utility, Xcel Energy.

Q So you don't get it through an ISO or do you?

A There is no general market exchange in Colorado. It's a regulated utility.

Q Just so I am clear, your testimony is is that you don't think a market, where people are bidding in on a daily basis, is as good of a competitive tool as compared to what's contemplated in the bid rule; is that right?

A I am not saying that it's bad in any respect. I took your other characterization of your question to mean that I absolutely agree that it's the best. And I am just saying, I think the jury is out on that, and I think that there are, perhaps, hybrid market conditions that -- or market structures that may provide a better potential outcome.

Q Right. You got a Master's in Business Administration from the University of California in

Berkeley, and you specialized in finance; correct?

A Correct.

Q You would agree, in my opening statement, I said, you can't see beyond the future. If something like an ISO or an RTO ever came to be in Florida, it would have the effect of, rather than having each utility plan for its own self, it would look at Florida as a whole, correct? You would agree with that, if you assumed a statewide RTO or ISO?

A I don't know what the rules of that would be, but I am willing to go along with your previse.

Q I am just asking factually, based on your testimony about being involved in industry restructuring and your expertise in markets.?

A ISOs are set up with different sets of rules, so I don't know what those rules would be in Florida.

Q Right. But if you assumed it was similar to other ISOs, RTOs, they plan on a -- not on a utility basis, they plan on a bigger basis geographically typically, correct?

A Correct. But I guess, again, pointing to California, the ISO does not plan -- does not go out and acquire the megawatts to maintain adequate reserves and reliability. That actually still falls to the utility. So even within ISOs, you can have rules in various states, where the obligation to keep lights on fall to different parties.

Q Okay. Thank you for your testimony.

CHAIRMAN GRAHAM: Mr. Cavros.

MR. CAVROS: No questions, Commissioner. Thank you.

CHAIRMAN GRAHAM: Staff.

MR. LAWSON: No questions. Thank you.

CHAIRMAN GRAHAM: Commissioners. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And thank you, Mr. Taylor, for your testimony.

I have some questions concerning the energy benefits that you used in your analysis of the RFP responses. And you used a 15,000 BTU per kilowatt hour reference case.

THE WITNESS: Correct.

COMMISSIONER BALBIS: Okay. And then for the Citrus County Combined Cycle, you assumed a 6,730 BTU per kilowatt hour?

THE WITNESS: Correct.

COMMISSIONER BALBIS: And I am trying -- since that unit is not in operation, and I assume that's just an estimate of what it would be, did you perform any sensitivity analysis to determine if the heat rate of Citrus County is, say, 7,000, would the energy benefit be adjusted so much so that it's no longer cost-effective, or did you do any type of analysis like that?

THE WITNESS: I did not. Basically, all of the 12 proposals that came in, NPGU being one of those 12, and the other 11 proposals, every bidder was kind of standing behind their heat rate. So that became the heat rate that went into my model to assess what the energy benefits of that particular proposal might be.

COMMISSIONER BALBIS: Okay. I understand that, but as far as the self-build option --

THE WITNESS: Uh-huh.

COMMISSIONER BALBIS: Let me back up. So you concluded that the Citrus County self-build option was $282 million, more cost-effective?

THE WITNESS: Correct.

COMMISSIONER BALBIS: Okay. And how much serve that is because of the energy benefits and how much of that is for the capital costs, O&M costs, et cetera.

THE WITNESS: In Table A7 of my independent evaluation report, that breaks things up into the fixed costs versus the energy benefits of the different portfolios, where the number one portfolio at the top, the least cost portfolio, did involve DEF's Next Planned Generating Unit. And then the next best portfolio was a combination proposals A and B.

So in response to your question, it looks like about $600 million of energy benefits over the 35-year period was associated with that $282 million differential, and that the fixed costs actually go in the other direction, that there will be greater fixed costs than under the proposals A and B.

COMMISSIONER BALBIS: Okay. So for the self-build option, there is $600 million in energy benefits?

THE WITNESS: Correct.

COMMISSIONER BALBIS: And would it -- would it be correct to be able to do a linear interpolation between the 15,000, which has zero energy benefit, and the 6,730, which has 600 million in energy benefits?

THE WITNESS: No. The Response Surface Model actually takes care of that interpolation, but it does it on a finer basis. And I think the linear interpolation out to the 15,000 would actually not get you reasonable numbers there. I am sorry I don't have that sensitivity that you are requesting in front of me, but I don't think that it would actually be a straight line.

COMMISSIONER BALBIS: Okay. And my concern is -- or just questions that I have is that, well, what if it's not 6,730, what if it's 7,000?

THE WITNESS: That's a good question.

COMMISSIONER BALBIS: And all the perceived energy benefits are not going to be realized, and now it's no longer cost-effective. And in looking at all of Duke Energy's other facilities -- and I know they are older units -- but the closest seems to be the Bartow Combined Cycle, which is 7,356. So if that's worse case, do all the energy benefits now go away, or did you look at that at all?

THE WITNESS: I did not. The 282 million, I should emphasize, I think is a low number for a number of other reasons. But you bring up a good point here, as far as the heat rate risk. Certainly, if it is higher than as was represented in the proposal that the internal DEF team provided, the energy benefits would not be as great as has been characterized in my results.

The -- but as I say, there were a number of other factors that I think were conservative in my analysis, such that I am really stating that the $282 million kind of a minimum differential.

One of the issues was I used, in order to fill out the portfolios, side fill resources that were combined cycle resources. We had discussions with the DEF evaluation team that, in theory, if we selected outside resources combined with smaller combined cycle resources, that would really trigger another RFP. We would be back here a year later, now kind of some circular process, that there was a risk of really packaging things with combined cycle side fill units, as I refer to them.

We did look at side fill units on the CT basis. Those obviously don't need to go through the Florida bid rule and the RFP process, but that added about $90 million to the 282.

So I don't have a number off the top of my head for you as far as the heat rate issue. I don't think it would be significant until you really started to move that heat rate up into 7,500 or 8,000, then you really are losing substantial energy benefits. But I think -- if it's somewhere in the neighborhood of what was proposed, I think that the conclusions at the table would still hold.

COMMISSIONER BALBIS: And do you know where that 6,730 number came from?

THE WITNESS: It actually came from the submission of the DEF internal team that submitted a bid into the RFP.

COMMISSIONER BALBIS: Okay. And then you mentioned that -- certain changes that would trigger another RFP. Do you think that the addition of Calpine into the Duke Energy mix would be enough of a change to trigger another RFP? So for example, these bidders bid on this scenario, and now perhaps the scenario has changed because there is another 510 megawatts in the system.

THE WITNESS: I don't think so, and I am basing that partly on the reaction of the marketplace to this RFP. It was, admittedly, underwhelming, and one of the major players in response to this RFP was Calpine.

So to a large extent, if you take Calpine out of this table, I have masked the identity of the bidders, but the results actually get worse because they are no longer a player in 2018.

COMMISSIONER BALBIS: If you don't change the need, because they are bidding against a 1,640 megawatt plant, correct?

THE WITNESS: Correct. But there would be one less player in the process.

COMMISSIONER BALBIS: Okay.

THE WITNESS: So I would just be concerned about the level of competition in conducting yet another RFP.

COMMISSIONER BALBIS: All right. Thank you. That's all I had.

CHAIRMAN GRAHAM: Other Commission questions?

Redirect?

MR. WALLS: A couple of followup questions, Mr. Taylor.

REDIRECT EXAMINATION

BY MR. WALLS:

Q The Hines -- I am sorry, the Citrus CC would be a new combined cycle technology, correct?

A Correct.

Q Okay. So the Bartow power plant that was put in line in 2009, if it was actually constructed and placed in commercial operation, what vintage, sort of technology, by year would they have been looking at for that plant?

A Probably something in the 2006 to 2007 timeframe.

Q And have there been improvements in the

combined cycle efficiency over that time period -- from that time period for when they were looking at building the Bartow plant to this time period, when they are looking at the Citrus CC?

A   Yes.

Q   And can you tell me if you are familiar with turbine manufacturer contracts who provide the basis for these heat rates?

A   Yes, I am.

Q   And do they --

MR. MOYLE: I'm just going to object. I just -- I think this is pretty far beyond the scope of cross-examination. He is getting into stuff that I don't recall anybody bringing up here on cross.

MR. WALLS: Well, I believe it was brought up in the questions by the Commissioner, and I was just elaborating on the response, so.

CHAIRMAN GRAHAM: I will allow it.

BY MR. WALLS:

Q   So do those manufacturers, do they provide guarantees in their contracts for the heat rates?

A   They can, yes.

MR. WALLS: No further questions.

CHAIRMAN GRAHAM: Okay. Exhibits?

MR. WALLS: We would move in to the record Mr. Taylor's prefiled direct testimony and hearing Exhibits AST-1 marked as Exhibit No. 35.

CHAIRMAN GRAHAM: We will move Exhibit No. 35 into the record.

(Whereupon, Exhibit No. 35 was received into evidence.)

MR. WALLS: And Mr. Taylor has no rebuttal testimony, so may he be excused?

CHAIRMAN GRAHAM: Mr. Taylor, travel safe. Thank you for coming.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN GRAHAM: So we are going to take up Mr. Borsch tomorrow, so we are going down to Mr. Hibbard, Calpine.

MS. TRIPLETT: Mr. Chairman, I am sorry. It occurred to me that when I looked at Mr. Scott had rebuttal testimony in the 111 docket, and given the fact that all of Calpine's witnesses, including Mr. Simpson have now been withdrawn. Mr. Scott only addressed Mr. Simpson's testimony, so I think that I would request that Mr. Scott's rebuttal in the 111 be withdrawn, because there is really nothing left in the record that he is responding to. And I am sorry I didn't realize that when we were talking earlier about the withdrawn witnesses.

CHAIRMAN GRAHAM: You see what you are doing to me?

MS. TRIPLETT: Sorry.

CHAIRMAN GRAHAM: Any objection to -- any objection to withdrawing Mr. Scott's rebuttal testimony?

Commissioner Balbis?

COMMISSIONER BALBIS: No, that was an accidental press of a button. I was going to, you know, question if she's removing another witness and go through that whole process, but I decided to save time.

MS. TRIPLETT: Sorry.

CHAIRMAN GRAHAM: Okay. So we will withdraw his rebuttal -- we will allow you to withdraw his rebuttal testimony.

MS. TRIPLETT: Thank you. And may he be excused from the hearing?

CHAIRMAN GRAHAM: And seeing no -- nothing, we will let -- Mr. Scott can go.

MS. TRIPLETT: Thank you, sir.

(Witness Ed Scott was excused.)

CHAIRMAN GRAHAM: Okay. Calpine, your

witness.

MR. WRIGHT: Thank you, Mr. Chairman. Calpine Construction Finance Company calls Mr. Paul J. Hibbard.

Whereupon,

PAUL J. HIBBARD

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Mr. Hibbard.

A Good afternoon.

Q Welcome to the Florida PSC.

A It's a pleasure to be here.

Q You previously took the oath of witnesses, did you not?

A Yes.

Q Are you the same Paul J. Hibbard who prepared and caused to be filed in docket 140110, which we call the Citrus County docket, or the big GBRA docket --

A Yes.

Q -- 48 pages of prefiled direct testimony?

A Yes.

Q Do you have any changes or corrections to that

testimony to be made today?

A No.

Q If I were to ask you the same questions posed to you in your testimony today, would your answers be the same?

A Yes, they would.

Q And with that clarification, do you adopt this as your sworn testimony to the Florida Public Service Commission?

A I do.

Q Thank you.

MR. WRIGHT: Mr. Chairman, we would request that Mr. Hibbard's testimony be entered into the record as though read.

CHAIRMAN GRAHAM: Let me make sure I understand. It's just going to be Mr. Hibbard's prefiled direct testimony only in docket 140110?

MR. WRIGHT: That's correct, sir. His testimony in the 111 docket has been withdrawn.

CHAIRMAN GRAHAM: Okay. I just want to make sure.

MR. WRIGHT: Thank you.

CHAIRMAN GRAHAM: We will enter that into the record as though read.

IN RE: PETITION FOR DETERMINATION OF NEED FOR THE CITRUS COUNTY COMBINED CYCLE POWER PLANT, BY DUKE ENERGY FLORIDA, INC. FPSC DOCKET NO. 140110-EI

DIRECT TESTIMONY OF PAUL J. HIBBARD

ON BEHALF OF

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

I. INTRODUCTION AND QUALIFICATIONS

Q: Would you please state your name, business address, and occupation?

A: My name is Paul J. Hibbard. I am a Vice President at Analysis Group, Inc. (AGI), an economic, finance and strategy consulting firm headquartered in Boston, Massachusetts, where I work on energy and environmental market, policy, and strategy engagements. My business address is 111 Huntington Avenue, 10th Floor, Boston, Massachusetts 02199.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Calpine Construction Finance Company, L.P., a subsidiary of Calpine Corporation (collectively "Calpine"), in support of its positions in Duke Energy Florida's ("Duke") Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 ("Petition"). Calpine owns and operates the Osprey Energy Center, which is located in Auburndale, Florida.

Q: Please describe your background and experience.

A: I have been with AGI for a total of almost seven years, first from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010, I served as Chairman of the Massachusetts Department of Public Utilities ("DPU"). While Chairman, I also served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. I also served as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnect States' Planning Council.

From 2000 to 2003 I worked in energy and environmental consulting with Lexecon, Inc. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, State Implementation Plans and emission control programs for the electric industry, with a focus on criteria pollutants and carbon dioxide ("CO_2"), as well as various policy issues related to controlling pollutants from electric power generators within the Commonwealth. From 1991 to 1998 I worked in the Electric Power Division of the DPU on matters related to utility integrated resource planning and procurement, utility ratemaking, restructuring of the electric industry in Massachusetts, the quantification of environmental externalities, energy efficiency, utility compliance with state and federal emission control requirements, regional electricity market structure development, and coordination with other states on electricity and gas policy issues through the staff subcommittee of the New England Conference of Public Utility Commissioners.

As a consultant, I have worked on numerous engagements related to power sector production cost modeling; resource planning and procurement; macroeconomic analyses; wholesale power market design, operations, and impacts; generation/storage optimization modeling; natural gas infrastructure development and evaluation; and energy and environmental policy design and analysis. I hold an M.S. in Energy and Resources from the University of California, Berkeley, and a B.S. in Physics from the University of Massachusetts at Amherst. My curriculum vitae is attached as Exhibit No. ___(PJH-1).

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide a quantitative and qualitative comparative evaluation of proposals currently before Duke Energy Florida ("DEF," or the "Company") and the Florida Public Service Commission ("Commission") to meet the estimated 470 megawatts of DEF's forecasted capacity and energy needs in the pre-2018 timeframe. Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc., Docket No. 140111-EI, Filed May 27, 2014 (hereafter "Petition"), at 11, ¶ 24. In particular, I have been asked by Calpine to compare the self-build proposal put forward by DEF – with a focus on DEF's proposed

Suwannee combustion turbines ("Suwannee CTs") – with the offer by Calpine to provide DEF a power purchase agreement ("PPA") followed by facility acquisition from Calpine's Osprey Energy Center ("Osprey" or "Osprey Facility") in Auburndale, Florida. I compare these proposals from the perspectives of (1) ratepayer impacts in terms of equivalent levelized cost of electricity ("LCOE"), cumulative present value revenue requirements ("CPVRR"), and considerations tied to risks borne by ratepayers; and (2) policy considerations related to power system reliability, investment and operational flexibility, and human health and environmental impacts.

Q: **Please summarize your testimony.**

A: In its Petition, DEF asserts that the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects are "…the most cost effective options to fulfill DEF's capacity and energy needs prior to 2018." Petition at 1. I disagree. Based on my review of cost and risk factors, I find that from a ratepayer perspective the best option for DEF is to accept Calpine's offer of a five-year PPA and acquisition (in year six) of the Osprey Facility. DEF's modeling and analysis occur largely within a black box, appear to be oversimplified and structurally biased, and inherently – and inappropriately – favor the Company's self-build alternatives. A more careful, common-sense review of the customer impacts associated with the various options reveals that by moving forward as proposed by DEF, DEF's ratepayers will likely incur significantly greater costs and be exposed to significantly greater risks than they would if instead of building the

Suwannee CTs, Calpine's offer is accepted. I conclude that selecting Osprey is the best outcome for ratepayers based on (1) a fully transparent comparison of the levelized costs of various alternatives; (2) a recalculation of cumulative present value revenue requirements starting from DEF's own calculations, with only a few reasoned adjustments reflecting current conditions and correcting for mistakes in DEF's original analysis; (3) a critique of the lack of transparency and apparent flaws in DEF's modeling approach and documentation; and (4) consideration of the nature, characteristics, and magnitudes of risks born by ratepayers under DEF's self-build proposal, compared with selecting Calpine's offer. Specifically, I find that Calpine's offer:

- has a levelized cost of electricity equal to $85.30 compared to $168.70 for the Suwannee CTs, and
- represents a cumulative present value revenue requirement *benefit* of $133 million compared to DEF's self-build proposal.

In short, Calpine has made an offer to DEF that represents a low-cost, low-risk, reliable, efficient, and environmentally responsible resource choice. DEF's analysis of alternatives fails to appropriately capture these many value streams, overstates the value of their own self-build alternative (in particular the Suwannee CTs), and understates the value of the Calpine offer. A reasonable evaluation of these alternatives, a common-sense comparison of facilities' levelized costs, and a review of important reliability, health, environmental and policy factors suggests that the best – and most prudent – option for DEF's ratepayers would be for DEF to accept Calpine's offer. Based on my review of all of these factors, I conclude that, in the interest of ratepayers and the energy policy and economic interests of the State of Florida, the Commission should deny DEF's Petition because it does not represent the most cost-effective alternative and because it is not in the best interests of DEF's customers.

Q: Are costs and cost-related risks the only benefit of the Osprey Facility compared to the Company's self-build alternative?

A: No. DEF's self-build alternative – when compared to the purchase of power and subsequent acquisition of Calpine's Osprey Facility – suffers from a number of additional flaws from the perspectives of power system reliability, flexibility, and environmental impacts. These are fundamentally important considerations for the Commission, particularly during this time of significant uncertainty and change in the electric sector. These changes are tied to highly uncertain growth forecasts for peak load and energy consumption, pending and emerging federal requirements related to the air, water, and solid waste impacts of electric generating facilities, and significant developments in the pricing and transportation of natural gas (for heating, process needs, and power generation). As discussed further below, an acquisition of the Osprey Facility helps address these uncertainties and reduces ratepayer risk, through a set of benefits which include: (1) the relative value of more efficient combined cycle ("CC") capacity (like the Osprey Facility) – compared to combustion turbine-only capacity – to meet DEF's changing resource needs and system conditions across multiple operating modes (baseload, intermediate, and peaking); (2) the option value provided by the higher capacity of the Osprey Facility compared to the Suwannee CTs, which would allow for greater flexibility for DEF to alter the timing of major new capital investments in future years (such as the proposed Citrus County facility) should load growth and/or resource availability deviate from current expectations; and (3) the wide-ranging human health and environmental benefits that flow from using the already-built and operational, efficient, and low-emitting (in terms of emissions per megawatt-hour ("MWh")) Osprey capacity instead of the new-construction, relatively inefficient, and higher-emitting Suwannee CTs.

Q: Are you sponsoring any exhibits with your testimony?

A: Yes. I am sponsoring the following exhibits:

PJH-1	Curriculum vitae of Paul J. Hibbard
PJH-2	Calpine LCOE Model Sources and Assumptions
PJH-3	Levelized Cost of Electricity ($2014/MWh)
PJH-4	Levelized Cost ($2014/MWh) by Capacity Factor 2015-2043
PJH-5	Growth in Total Energy Demand and Potential Energy Generation from Generic Combined Cycle Units
PJH-6	Comparison of Osprey Capacity Factor and Starts, by Year, DEF Production Simulation Results, Scenario 5 Acquisition
PJH-7a, 7b	Adjustments to Cumulative Present Value Revenue Requirements
PJH-8	Emission Rates by Technology, Carbon Dioxide (CO_2) and Nitrogen Oxides (NOx)

Q: How is your testimony organized?

A: In Section III, I present my ratepayer impact analysis, including a transparent analysis of the levelized costs for each of the Calpine and DEF facilities in the pre-2018 resource procurement, an evaluation and recalculation of DEF's own conclusions with respect to CPVRR, a discussion of the shortcomings associated with DEF's analytic method and modeling effort, and a review of the significant risks ultimately borne by ratepayers under different scenarios. In Section IV, I address important considerations related to system reliability, planning and procurement flexibility, and human health and environmental impacts. Finally, in Section V, I summarize the conclusions I draw from my review of these factors.

III. CALPINE'S OFFER IS HIGHLY BENEFICIAL FROM THE PERSPCTIVE OF DEF'S RATEPAYERS

III.A OVERVIEW

Q: How is this Section organized?

A: In this Section, I address factors related to DEF's analysis of the value of competing resource options, from the perspective of DEF's ratepayers. Specifically, in Section III.B, I compare Calpine's proposal and DEF's proposed self-build projects on the basis of LCOE, presenting the analytic method, assumptions, underlying data, and results. The LCOE analysis – when presented clearly with the assumptions that go into the calculations – provides a fully transparent and straight-up comparison of the capital and operating costs of resources in the most relevant and understandable metric from a ratepayer's perspective – dollars per MWh of electricity generated over the life of the facility. The results demonstrate the clear and compelling benefit to ratepayers of the Osprey PPA/acquisition in comparison to DEF's self-build proposal, the Suwannee CTs.

In Section III.C, I first discuss various flaws of construction and execution that exist in the modeling and analysis that DEF used in its evaluation of resources in this docket. Despite these flaws, I demonstrate that even accepting DEF's analysis as the starting point, the Osprey Facility is the best from a CPVRR perspective when DEF's results are adjusted to correct certain mistakes and misrepresentations in the original calculations.

Finally, in Section III.D, I highlight the need for heightened attention in this docket to the different ratepayer risk factors and discuss differences in the risks borne by ratepayers between the options of moving forward with development, permitting and construction of the Suwannee CTs versus selecting the Osprey PPA/acquisition proposal offered by Calpine.

III.B. LEVELIZED COST OF ELECTRICITY

Q: Is it possible to construct an analysis that provides a clear and transparent comparison of proposals from the perspective of electric ratepayers?

A: Yes. One of the challenges in understanding DEF's analyses of resources proposed in this proceeding is the substantial level of opacity – or, put differently, the substantial lack of transparency -- in the way in which DEF has assembled competing resource portfolios, forecasted the build-out of its system over a very-long modeling time frame, and evaluated bids using a proprietary "black box" model. This does not mean that DEF's analysis is not valuable – it is. However, it is critically important that the Commission and stakeholders also have access to a robust *and transparent* quantitative analysis of bids considered by the Company and the Commission; one that allows for a more clear and objective understanding of the relative value of each proposal. One way to do this is through a clearly documented levelized cost of electricity analysis, in which the capacity, energy, and other cost elements in project proposals are translated into an equivalent dollars-per-megawatt-hour ($/MWh) metric, using consistent financial, market, and temporal assumptions across all proposals.

Q: What is the value of carrying out a LCOE calculation, and how have you approached the LCOE analysis in this instance?

A: In this docket, the Commission is being asked to determine whether DEF's selection of its self-build proposals, from among multiple proposals and resources with different terms, cost elements, technologies, and operational utilization factors, is in the best interests of its customers. Most importantly, the projects in this solicitation differ in at least two fundamental ways. First, they include, on the one hand, firm PPA and acquisition proposals from merchant generators (with multiple-year terms, pre-set power purchase and acquisition price points, and various operational and financial guarantees), and, on the other hand, self-build project cost estimates from the incumbent utility (with no term or cost guarantees from the ratepayer perspective). A comparison of bids under these circumstances must include a clear and transparent demonstration of how assumptions related to the different terms and payment structures affect the expected cost and value of different bids.

Second, the proposals in this solicitation include projects whose use in daily operations is fundamentally different from the standpoint of frequency, duration, and timing of commitment and dispatch. The Suwannee CTs will have a very different operational profile (infrequent, short-duration operations) than that of the Osprey and/or other CCs (more frequent operations and longer run times). A comparison of bids under these circumstances should create a transparent demonstration of how expectations or assumptions regarding resource use affect the expected cost and value of different bids.

LCOE analysis is able to capture these fundamental differences in a transparent manner, and enables a relatively straightforward and consistent comparison of bids. Below, I present a LCOE analysis of the DEF self-build projects and Calpine's proposal – the Osprey Facility – that are available to meet the needs of DEF's customers. My purpose for, and approach to, the LCOE analysis was to construct a fully independent, objective, and transparent analysis that treats all offers on an equal and fair basis.

The LCOE metric for each proposal represents the net present value of the expected annual revenue requirement – including the sum of variable and fixed operation and maintenance costs, capital costs, and the return on investment – divided by the estimated annual generation over the terms of the proposals. The LCOE calculation establishes annual costs in accordance with contract terms (in the case of PPAs), or using traditional calculations of annual revenue requirements (in the case of utility self-build or acquired units that would go into the utility's rate base), in order to create comparability across structural differences in proposal pricing and asset lives. In addition, the LCOE analysis accounts for differences in utilization between resource types through variable capacity factor inputs that determine average annual generation.

The LCOE analysis compares ratepayer impacts of each proposal under a user-specified set of capacity factor assumptions. While an LCOE analysis does not include dispatch simulation, and thus it does not quantify the economic and environmental benefits of displacing generation, ignoring such benefits would tend to underestimate the value of CC capacity relative to CT capacity, since the more efficient and more highly-utilized CC capacity would likely generate greater price and emission displacement than CT capacity. Thus the value of the Calpine proposal may be substantially better than indicated by its LCOE relative to the LCOE for the Suwannee CTs.

In short, and as discussed further below, the Strategist model is fairly impenetrable to most of those who are not actually running the model, generates results that are strongly dependent on assumptions and on how resources are configured in model runs, and thus in a sense provides the Commission with "take it or leave it" results. LCOE analysis, on the other hand, is a highly accessible, transparent and useful representation of the ultimate impacts on ratepayers, and thus provides an extremely valuable and important sanity check on the results emerging from black-box models.

Q: Please describe Calpine's proposal to Duke for power supply from the Osprey Facility as you have modeled it in your analysis.

A: For the purposes of my analysis, I have used Calpine's most recent offer, which is summarized in the direct testimony of Mr. Todd Thornton, Senior Vice President, Origination and Development for Calpine (hereafter, "Thornton Direct"). Specifically, I understand Calpine's most recent offer to include:

- A five-year PPA, starting January 1, 2015 and extending through December 31, 2019, with an initial capacity payment of [redacted] in 2015 escalating to [redacted] in 2019. This price applies to the full 515 MW of Osprey's contracted capacity under the PPA; and
- An option for Duke to purchase the plant on January 1, 2020 for [redacted] in nominal 2020 dollars).

From the direct testimony of John Simpson (hereafter "Simpson Direct"), I understand that due to transmission system limitations, Osprey may not be able to provide the full capacity benefits of the facility (i.e., the 515 MW of contracted capacity under the PPA, and the 599 MW of total capacity available after Duke acquires Osprey) in every single hour of the year until construction of related transmission infrastructure upgrades are completed, even though it is likely to be able to provide up to full capacity *in the vast majority of the* hours of the year. In any event, the quantity of capacity that *can be* supplied on a firm basis prior to new transmission infrastructure – 249 MW – is sufficient to meet DEF's reliability need in the interim period. Nevertheless, for the purposes of the LCOE analysis, during the 5-year PPA period, I assumed annual capacity payments equal to the product of the proposed capacity payment and the contracted capacity (515 MW) to be provided under the PPA, as specified in the offer. This represents the maximum possible capacity payment obligation for DEF under Calpine's offer. Following an acquisition in 2020, I continue to calculate the LCOE using 515 MW of capacity. This is a conservative assumption that tends to undervalue the peaking capabilities of the Osprey Facility. I discuss – but do not quantify – the value of this additional duct-fired capacity for DEF ratepayers in Section IV below.

Q: Please summarize your understanding of DEF's self-build proposals.

A: DEF has proposed two separate projects to meet its generation supply needs before 2018. The Suwannee CTs are two combustion turbines with summer capacity of approximately 316 MW of summer capacity and 375 MW of winter capacity with an estimated in-service cost of $197 million. The Suwannee CTs would have an annual net operating heat rate of 10,197 Btu per kilowatt-hour. The Hines Chillers would add approximately 220 MW of capacity during summer conditions with little degradation of the heat rates of the Hines combined cycle units. The Hines Chillers would not add any capacity to DEF's system during winter peaking conditions. The estimated cost of the Hines Chillers is approximately $160 million.

Q: Please provide a summary of the results of the LCOE analysis you conducted.

A: I estimated the LCOE for the Osprey PPA/acquisition proposal, the Suwannee CT, the Hines Chillers, and the combinations of Suwannee/Hines and Osprey/Hines. I used information on capital costs, operating costs, financing costs, fuel costs, and pollutant emission costs that were provided in Mr. Borsch's testimony and responses to Calpine's interrogatories. For Osprey, I used the updated pricing offer details provided above. A summary of my assumptions is included as Exhibit No. __ (PJH-2) and described below.

Key results presented in Exhibit No. __ (PJH-3) include the following:

- Calpine's Osprey Facility PPA/acquisition offer has the lowest LCOE across all of the options after considering total capacity costs, transmission costs, and energy costs. Osprey's LCOE is 19 percent lower than the Hines Chillers and 49 percent lower than the Suwannee CTs.
- A combination of Osprey plus the Hines Chillers offers a lower LCOE than either the Hines Chillers alone or in combination with the Suwannee CTs.
- The Suwannee CTs have the highest LCOE of all three units, which is driven by the lower expected utilization and higher heat rate of a combustion turbine as compared to a highly efficient combined cycle unit.

Q: Please summarize the key assumptions in the LCOE analysis.

A: I relied on three key documents for the data used in this analysis. First, I obtained capital cost, operational data/heat rates for the self-build units, and capacity factors from Mr. Borsch's testimony. Second, I used pricing information for the Calpine PPA/acquisition from the updated terms offered on July 3, 2014 as described in the Thornton Direct. Third, I used data from the Strategist inputs and outputs provided to me as part of DEF's responses to Calpine's discovery requests. This included fixed O&M, variable O&M, start costs, natural gas transportation costs, and environmental costs for both the Osprey acquisition and the DEF self-build units.

For financial assumptions, I used DEF's current weighted average cost of capital ("WACC") for both return on rate base and the discount rate, and where appropriate, made conservative assumptions about asset lives and depreciation that would tend to increase the cost of the Osprey PPA/acquisition proposal relative to the Suwannee CTs. For income accounting, I assumed that assets followed a modified accelerated cost recovery ("MACR") schedule. I used a 20-year schedule for combined cycle and transmission assets and a 15-year schedule for combustion turbines, consistent with guidance found in IRS Publication 946.

Q: Please summarize key financial assumptions in the LCOE analysis.

A: Whenever possible, I used assumptions that would tend to disadvantage the Calpine offer relative to the DEF self-build proposals, and I have tried to present an analysis that accounts for the applicable regulatory accounting standards. For example, I assumed that all assets (including transmission) would be depreciated on a straight-line basis from the in service year to 2043, and that the return on rate base would be collected on the non-depreciated portion in each year. For the transmission direct connect, this period is likely too short, which will tend to increase the cost to ratepayers for this project in my analysis and disadvantage the Osprey bid as compared to the Suwannee CTs. In addition, I assumed a 35-year asset life, which means that not all costs are recovered within the 2043 study period. Again, this tends to underestimate the cost of the Suwannee CTs to ratepayers in my analysis.

For Osprey and Hines, I assumed useful lives through the end of the study period, which is equivalent to a total useful life of 40 years. I believe this is a reasonable assumption based on the operational longevity of DEF's generating assets. *See, e.g.*, Florida Public Service Commission Order No. PSC-10-0131-FOF-EI issued March 5, 2010, at 17, 19 (stating that "several of PEF's steam units and combustion turbines on its system have been in service for more than 40 years, and all are projected to be in service longer than 40 years," and concluding that "on balance, we find a minimum life span of 35 years shall be used in this proceeding for PEF's combined cycle units… PEF should likely experience life spans of 40 years or more…").

Finally, for AFUDC, I have made a simplifying assumption that all funds are placed in rate base at the weighted average cost of capital. This tends to underestimate the amount of monies that will be collected, since I understand that the AFUDC weighted average cost of capital is 7.44 percent. 14LGBRA-

NRGROG1-79-000005 – 000007 AFUDC Rate Change Schedules A-C_March 2010_Final.xlsx.

Q: Please describe your approach to assigning capacity factors to resources for the purpose of the LCOE analysis.

A: For the Suwannee CTs, I used the 9.3 percent capacity factor presented in Exhibit BMHB-2. For the combined cycle units, I used a [redacted] I also tested my results against a wide range of capacity factors. The conclusions I draw are robust to changes in expected output, even including unrealistic combinations of low capacity factors for CCs and high capacity factors for CTs. *See* Exhibit No. __(PJH-4).

Q: How can you determine whether the LCOE results are robust to changes in expected capacity factors for the different resource options?

A: The LCOE model determines the levelized cost of electricity for a given resource at an assumed annual average level of utilization. That is, in calculating the LCOE of $85.30/MWh for the Osprey PPA/acquisition (shown in Exhibit No. __PJH-3), I assumed an annual average capacity factor [redacted]. This determines in each year the total MWh of generation over which to spread the combined investment, fixed, and variable costs to arrive at the levelized cost on a per MWh generated basis. Appropriately, since future years are discounted, the capacity factor outcomes in early years weigh more heavily than later years in the lifetime LCOE calculation.

It is reasonable to ask whether the LCOE benefit of the Osprey Facility remains at lower capacity factors, and/or at higher capacity factors for competing proposals. Exhibit No. __(PJH-4) provides insight into this question by showing the LCOE in $/MWh for both Osprey and the Suwannee CTs as a function of annual average capacity factors (assumed or projected). For example, at the intersection of the horizontal and vertical dashed lines in Exhibit No. __ (PJH-4), you see that at a [redacted] the LCOE for the Osprey PPA/acquisition is $85.30/MWh. On the other hand, the dashed line higher on the curves, and to the left, shows that with the Suwannee CTs operating at an annual average capacity factor of 9.3 percent, the Osprey proposal has an equivalent LCOE at an annual average capacity factor of approximately [redacted]; further, at *any capacity factor greater than* [redacted] the Osprey proposal has a lower LCOE than the Suwannee CTs. Finally, as long as Osprey is expected to operate at an annual average capacity factor of about [redacted] or more, it will be better from an LCOE perspective than the Suwannee CTs operating at *any* capacity factor.

III.C. THE COMPANY'S EVALUATION OF COMPETING PROPOSALS

Q: DEF has used the Strategist optimization model to compare proposals in this proceeding. Should the Commission rely only on the Company's Strategist analysis?

A: Absolutely not. The decision made in this proceeding will affect ratepayer costs, risks, and system operations and reliability for decades. Given the importance of this decision, the Commission should carefully understand and consider the Strategist results. Given modeling limitations (discussed below), the Commission also needs to view the results within the totality of the evidence from all of the modeling and analyses presented by parties in this proceeding. This is particularly important given that Strategist is a proprietary "black box" model, one whose unit commitment and dispatch module is opaque and admittedly simplistic, in ways that are clearly of heightened importance in comparing technologies offered in this procurement. One value of the LCOE analysis I present is that it provides a fully transparent and straightforward assessment of the cost of proposals to ratepayers in a manner that provides the Commission with an additional analytical tool to inform its decision.

Q: Did you review the Strategist results and CPVRR estimates that DEF presented in this docket?

A: Yes. In particular, I reviewed the Strategist inputs and outputs that were provided to me in DEF's responses to Calpine Interrogatories 6 and 7, and that I understand to be associated with the Calpine Osprey Facility, known as PPA1 and Acquisition 2 in Exhibits BMHB-8,-9, and -10. Company witness Borsch asserts that Acquisition 2 had a $193 million CPVRR deficit compared to the DEF self-build option and that a PPA modeled from 2016-2021 and replaced by generic back-fill CC and CT units had a $129 million CPVRR deficit compared to the DEF self-build option. Mr. Borsch noted that the negative CPVRR in the acquisition case was "largely due to transmission system upgrades" required to incorporate the facility into the DEF system. Borsch Direct at 46. Notably, in Exhibit BMHB-9, Mr. Borsch also presented a range of CPVRR values for each bid. In this scenario, Acquisition 2 was modeled with a positive CPVRR of $39 million, under assumptions that are much closer in detail to the current Calpine offer being considered by DEF. (For example, this included a [redacted] “14LGBRA-NRGROG1-28-000001 – 000008 CONFIDENTIAL Results_Sensitivities_01212014A.xlsx”) In Exhibit BMHB-10, Mr. Borsch presented a final, detailed economic analysis.

Q: What is your opinion on the Strategist results presented in this docket?

A: The key difference between a LCOE analysis and the Strategist model’s CPVRR estimates is the incorporation of a production cost calculation in the Strategist analysis. LCOE analyses do provide insights into production cost impacts, in the sense that levelized costs are a function in part of the assumed capacity factors in the analysis. (As described above, in Exhibit No. PJH-__4, I present a chart that allows the Commission to see *explicitly* how different capacity factor assumptions or outcomes affect LCOE results.) Configured appropriately, 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. However, in this instance, and based on the review of the information DEF has provided in this proceeding related to its Strategist analysis, I believe there are a number of questionable elements of the production cost component of that analysis that may seriously compromise the value of its results.

Q: Are you familiar with production cost modeling?

A: Yes. I have led or participated in numerous engagements as a consultant involving the use of production cost modeling to explore asset values and assess the cost or environmental impacts of various public policy choices. Specifically, in these projects we have used either Ventyx's Promod production cost modeling tool, or General Electric's GE MAPS tool. Both are transmission-constrained, hourly production cost modeling programs.

Q: Please explain your concerns with respect to the production cost elements of DEF's Strategist analysis in this case.

A: First, my understanding is that, in the interest of modeling time and integration with the other Strategist modules, the production cost modeling algorithm within Strategist is far more simplistic than standard production cost models – such as Promod and GE MAPS – that are more often used for investigative system dispatch simulation analyses. In particular, the Strategist model does not require an hourly dispatch approach (instead allowing the user to rely on a limited set of load representations, with results extrapolated into full-year calculations), nor does it dispatch the system with attention to constraints that may exist on individual transmission elements. Further, its representation of unit operational capabilities and the logic by which units are committed (or "turned on") and kept on in consideration of multi-hour variations in system load

- may fail to capture operational details that could be important in understanding the relative value of CC versus CT technologies on the Company's system.

In short, the quality or value of the Strategist production cost modeling results – in terms of unit capacity factors and unit production cost benefits – should be taken with a healthy degree of skepticism. In addition, the logic behind how units or resource portfolios are configured in the model, and how generic units are added over time, can obfuscate or wash out insights into the relative value of competing resource alternatives added today. Based on my review of the Strategist inputs and outputs provided to me in the course of this proceeding, I believe this is likely to be the case in this instance, and I have a number of serious reservations about other specific and key modeling choices – and thus the production cost modeling results – that affect CPVRR outcomes in this case.

For example, between 2018 and 2043, DEF included over 4,000 MW of generic combined cycle capacity in its Strategist modeling analysis, presumably to meet its 20 percent reliability margin and satisfy growth in retail peak load. However, this may represent an unwarranted and costly overbuilding of the system. While these generic CC additions meet the *peak load* requirements, their potential incremental contribution of energy vastly exceeds DEF's annual energy growth needs, as shown in Exhibit No. __ (PJH-5). The compound annual growth rate in the potential energy generation from these units, starting from the 2018 Citrus County addition, is 4.5 percent. This far exceeds the total energy demand growth rate of 1.0 percent over the 2014-2043 period. From a production cost perspective, this modeling choice has little or no impact on the value of the self-build Suwannee CTs, but tends to wash out the production cost value of Calpine's efficient CC capacity.

However, within the Strategist model, these generic units operate at a relatively high efficiency, with capacity factors between 60 and 80 percent, dramatically – and artificially – (1) reducing the utilization of Osprey (and other CC capacity on the system) and thus the positive energy benefit of that resource option, and (2) increasing the number of starts at Osprey by over 100 percent, increasing the cost of that resource option as shown in Exhibit No. __ (PJH-6).

In reality, the more prudent choice of resource additions from a ratepayer perspective would likely better utilize the energy capacity of the existing combined cycle fleet to meet growth in total energy requirements, probably using an optimized combination of more targeted CT and/or CC duct firing technology to meet future peak demand needs.

Q: Are you suggesting that DEF is committing to an over-build of expensive CC capacity in the future?

A: No. The addition of generic CC capacity is a modeling artifact. I would expect that over time as DEF's actual resource needs materialize, the Commission will expect DEF to select the best set of resources to meet growth in peak load and annual energy, in consideration of the load, resource, and cost expectations in place *at that time*. My point in raising this concern is to illustrate the way in which I believe future changes in infrastructure have been modeled in Strategist for this evaluation inappropriately and artificially discount the value of Osprey relative to the self-build option, and skew the CPVRR results in favor of the Company's proposed outcome.

Q: **You have concluded that the production cost modeling component of Strategist likely understates the production cost benefit of Osprey relative to the competing self-build proposals. Can this be corrected without reconfiguration and re-running of the Strategist model at this time?**

A: No, I do not believe it is possible to accurately "adjust" Strategist results after the fact for assumed differences in production cost modeling configurations. The only way to do this would be to re-run Strategist or – ideally – an alternative production cost modeling tool, under different scenarios and resource portfolios to develop a more accurate representation of the likely benefits and costs of competing proposals from a production cost perspective.

Q: **Are there other elements of the Strategist modeling that may influence the results, and that can be adjusted after the fact?**

A: Yes. There are a number of factors in the Company's CPVRR results tied to financial assumptions and the underlying capital and fixed costs of proposals that incorrectly represent the proposals before the Company and the Commission at this time. These factors can – and should – be corrected for the Commission to have an accurate portrayal of the impact of competing proposals on ratepayers. For example, the estimate of costs associated with transmission upgrades to fully capture the capacity value of the Osprey Facility is vastly overstated in the original CPVRR calculations. As described in the testimony of John Simpson, the actual cost to accomplish this – through a direct connect transmission upgrade that not only would allow integration of Osprey's full capacity to serve DEF's customers, but would also provide meaningful reliability benefits to the DEF and FRCC systems – is likely no more than $150 million, and could be less. Simpson Direct at 12. In addition, as described in the testimony of Todd Thornton, Calpine has reduced its acquisition sale price from $300 million to $[redacted] in 2020, accompanied by reduced capacity payments on a PPA from 2015 through 2019. Thornton Direct at 7-8. Since these factors only affect fixed costs and investments, they would not affect production cost modeling outcomes (which are a function of variable costs only). Thus, adjusted CPVRR results may be approximated by adjusting for different fixed cost and financial assumptions, holding all else equal.

Q: Have you evaluated the impact of these updated pricing changes on the CPVRR?

A: Yes, I have. Exhibit No.__ (PJH-7) highlights the results of these adjustments. In order to do this, I had to start with CPVRR results that DEF has already generated in this docket. Specifically, I start with DEF's CPVRR estimate of negative $193 million (compared with the self-build proposal) calculated for the acquisition of the Osprey Facility in 2014. After accounting for new estimates for the direct connect transmission upgrades, and including the CPVRR impacts of the acquisition and PPA costs of Calpine's current offer, and adjustments for gas reservation charges, I find that the CPVRR of an Osprey PPA/acquisition relative to the DEF self-build option is, at a bare minimum, positive $133 million.

Q: **Do you believe this accurately captures the value to DEF's customers of the Osprey PPA/acquisition relative to DEF's proposed self-build projects?**

A: No, I do not. In this recalculation, I only considered the impact of the timing and magnitude of capital costs on the total CPVRR. As described above, I believe that the way in which DEF structured its evaluation of proposals and calculated production cost costs and benefits likely understates the value of the Osprey Facility. This means that the negative $193 million starting point is, in my view, significantly overstated (i.e., more negative than it should be). Thus, if adjusted and corrected for the true dispatch value of the Osprey Facility, the positive recalculated CPVRR value for the Osprey PPA/acquisition would start at a less negative CPVRR number, and thus should significantly exceed the $133 million customer CPVRR benefit calculated for changes in generation and transmission capital costs and gas reservation adjustments presented in Exhibit No. __ (PJH_7).

Q: **Please describe your capital cost adjustments to the CPVRR in greater detail.**

A: In Exhibit No. __ (PJH-7), I made two adjustments to the capital costs for generation and transmission that I understand to have been included in Mr. Borsch's CPVRR estimates.

First, I estimated the impact of the new and lower acquisition price offered for the Osprey Facility. As noted in the testimony of Todd Thornton, Calpine provided DEF an updated offer including an acquisition price o[redacted] a closing on January 1, 2020. Accounting for the new PPA/acquisition offer required three steps.

The [redacted] sale price offers a significant value to ratepayers compared to the $300 million original sale price. In adjusting the CPVRR estimate for this new acquisition price, I first accounted for the impact on revenue requirements, including depreciation, return on rate base, and income taxes. I estimate that the impact of a $[redacted] reduction in sale price is equal to a net positive of [redacted] in CPVRR value.

Second, based on the information I reviewed, it appears that DEF originally modeled the acquisition purchase investment as happening in 2014. Duke Energy Florida, Inc., response to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-9), Competitively Sensitive Confidential Response 6a and 6l. (hereafter, "DEF IR"). However, pursuant to Calpine's offer, the asset purchase would be booked in 2020. Adjusting for this difference in terms of the time value of money, I estimated that an asset sale booked in 2020 instead of 2014 would result in an additional [redacted] benefit from a CPVRR perspective.

Calpine's current proposal also contains an initial five-year PPA prior to the acquisition starting at [redacted] in 2015, escalating to [redacted] in 2019. Thornton Direct at 7-8. Because I accounted for the acquisition in

2020, I added back into the CPVRR estimate the net present value of capacity payments under the updated PPA agreement. Pursuant to the terms of Calpine's offer, the capacity payments are based on the 515 MW of Osprey's contracted capacity under the PPA, even if prior to construction of the direct connect transmission upgrade DEF may not have access to the full capacity in certain hours of the year. The resulting total PPA capacity payments over this period are equal to approximately [redacted].

The net impact of these three adjustments is [redacted] in positive CPVRR benefits for ratepayers, as shown in Exhibit PJH-7A and PJH-7B.

Next, I also accounted for the lower estimates for transmission upgrades. Mr. Borsch included [redacted] in transmission costs for an acquisition scenario. DEF IR2. However, DEF's transmission expert Edward Scott noted that the best approach to integrating Osprey within DEF's system would be to establish a direct connection of Osprey to the DEF balancing authority area ("BAA") (the "direct connect" project), and that that could be completed with two new 230 kV transmission lines from Tampa Electric Company's Recker Substation to both the Kathleen and Haines City East substations at a total cost of approximately $150 million. Florida Public Service Commission, Docket No. 140111-EI, Direct Testimony of Ed Scott (hereafter "Scott Direct"), at ES-3, 2 of 4. Calpine's transmission expert John M. Simpson has confirmed that the cost of such a project is not likely to exceed this amount (and could be meaningfully less), and that in addition to addressing any DEF or third-party interconnection/upgrade requirements, such a direct connection would also provide a number of ancillary benefits to the DEF and Tampa Electric Company balancing authority areas. Simpson Direct at 15. I apply the same method as in the acquisition price adjustment above to estimate corrections to CPVRR for this lower transmission upgrade cost. In short, this improves the CPVRR of Osprey relative to the DEF self-build proposal by approximately [redacted].

The net impact of only these two adjustments for Calpine's updated PPA/acquisition offer and updated transmission cost estimates — is that an Osprey PPA/acquisition mix results in CPVRR benefits to ratepayers – relative to the DEF self-build proposal, of approximately [redacted]

Q: Are there other fixed costs in Strategist that the Commission should consider?

A: Yes, it appears that DEF has modeled Osprey with firm gas transport but failed to include a similar or comparable cost for the firm gas transportation service available to serve the Suwannee CT units. DEF IR6g and 10a. This creates issues of comparability, and puts Osprey at a cost disadvantage relative to the Suwannee CTs.

Q: What is the financial impact of including the costs for firm gas transportation service for some units but not for others?

A: The cost difference on a CPVRR basis is substantial. DEF modeled annual firm gas service for Osprey at [redacted] per year. DEF IR6g. On a net present value basis, this is equal to [redacted], assuming firm gas transportation costs are passed directly on to ratepayers. This single fact alone accounts for almost the full difference ascribed to an Osprey acquisition in this docket. DEF also included firm gas transportation service for an Osprey PPA scenario and the generic CT units that replace it in 2022.

However, I understand that DEF maintains long-term firm transportation agreements that support its existing plants and that DEF already has sufficient firm transportation for gas to the Suwannee location. Duke Energy Florida, Inc.'s Responses to NRG Florida LP's First Interrogatories Nos. 1-108 to Duke Energy Florida, Inc., Response 36. If this is indeed the case, then a true apples-to-apples comparison would allocate a portion of the existing firm fuel gas costs that would otherwise go to serve the new Suwannee CTs. That is, presumably DEF manages fuel commodity and transportation on a fleet-wide basis to minimize the overall cost of electricity generation to ratepayers, and optimizes existing commodity and transportation contracts across its fleet with this objective in mind. Yet in the analysis, DEF has existing natural gas transportation rights that are reserved to benefit their self-build unit in CPVRR calculations, but are not comparably credited to *a competing resource* that, if selected, would eliminate the need to assign such rights to the self-build resource.

In my view, this compromises the fairness of the resource evaluation, creates an unlevel playing field, and could contribute to solutions that are imprudent or not optimal from a ratepayer perspective. Because gas transportation contracts – are to some degree – transferrable products, DEF should be able to accommodate 320 MW of generation from *any* proposal in this docket under its existing gas transportation contracts. Therefore, in Exhibits PJH-__ 7a and 7b, I include an additional CPVRR adjustment of [redacted], which is equal to [redacted]

Q: What do you conclude based on your analysis?

A: Based on my review of a relatively simple set of adjustments to CPVRR results, I conclude that – even assuming that in all other ways DEF has appropriately modeled the resources compared in this procurement (which, as discussed above, I do not believe) – the Osprey PPA/acquisition is the best deal for ratepayers in terms of CPVRR.

The net effect of the adjustments I have described above – accounting solely for changes in capital costs for generation and transmission and fixed expenses related to gas reservation charges – has a total CPVRR benefit of $133 million. My adjustments reflect current conditions and a comparison of the two units that I believe is not only more appropriate, but is supported by DEF's own analysis in this docket. As I described above, Mr. Borsch also found that Acquisition 2 had a positive CPVRR of $39 million, under a scenario with a [redacted] million purchase price and [redacted] million in transmission costs, both of which are much closer in detail to the current Calpine offer being considered by DEF. "14LGBRA-NRGROG1-28-000001 – 000008 CONFIDENTIAL Results_Sensitivities_01212014A.xlsx"

Furthermore, as I describe below, Mr. Borsch also tested the sensitivity of his results to "construction cost[s]…, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks" among other things. The difference between the high and low sensitivity cases for the DEF self-build proposals was negative $176 million. To the extent that any of the DEF self-build proposals experience cost over-runs consistent with Mr. Borsch's assumptions, some portion of his negative $167 million and my positive $133 million CPVRR adjustments may be additive, suggesting even greater value to DEF ratepayers.

III.D. RATEPAYER RISKS

Q: In light of the fact that the proposals being reviewed by the Commission in this proceeding result from a competitive process, why do you think it is important to comment on ratepayer risks as part of your testimony?

A: In any competitive procurement involving utility and non-utility alternatives, it is vitally important that the Commission give due consideration to the different risks that procurement options have from the perspective of the utility's ratepayers. For decades, many public utility commissions – including this Commission – have required that utilities test self-build options through competitive solicitations in order to impose the discipline of competition on utility self-build project design and pricing. The goal of obtaining the best result for customers relies not only on competition to allow for discovery of the best offer prices from suppliers, but it also depends upon discovering and weighing any differences in the risk profile of the competitive offers. Price is certainly one aspect of getting the best deal for ratepayers; the development status and the terms and conditions under which a product is proposed at a particular price also affects the relative value of different competitive offers to consumers.

Q: Please explain further what you mean by the impact on consumers of the terms and conditions under which a product is supplied.

A: We see this relative "risk" principle at work often in the electric industry. Utilities must make decisions at one point in time about investments and other commitments that could be greatly affected by events that will occur much later, and which may or may not comport with the original expectations. Development uncertainty can lead to delays, changes in costs, and unexpected outcomes. Labor and material costs change. Fuel prices change. Public policy will change. Consumer habits change. Countless things can change, so that – after the fact – the original decision to select a particular power plant may end up looking like a very good deal or a very bad failure. Many of these conditions – variations in development status and permitting requirements, open versus guaranteed pricing, and uncertain versus guaranteed performance – are before the Commission in this case.

Q: In your view, does Calpine's proposal appropriately manage the risks related to new resource acquisition?

A: Yes. From a customer's perspective, the risk profiles of the various options available to DEF are significantly different. DEF, for example, seeks to pass through to ratepayers a return of and on the actual dollars of power plant investment (into utility rate base), including any cost overruns, provided the Company can demonstrate that any cost overruns "...were prudently incurred and due to extraordinary circumstances." DEF IR9, Docket No. 140110-EI. In other words, while DEF has provided an estimate of the costs to develop, permit and construct the Suwannee CTs – and that estimate is the basis for evaluating its proposal relative to other proposals – if the actual costs come in much higher, DEF surely expects to recover the additional costs unless the cost overruns could be proven to be due to incompetence or imprudence in project management. For the purposes of my analysis, I have assumed a $197 million total cost for the Suwannee CTs, even though there may still be uncertainty in DEF's expectation of ultimate costs. For example, as included in Exhibit BMHB-2, Schedule 9, as recently as January 2014 DEF estimated a total installed cost of $661.57/kW. Based on 316 MW of summer capacity, this equates to an installed cost of $209 million. In addition, it is not possible to know with certainty how reliably and efficiently the facility will operate when needed until it has been constructed and operated under normal and peak system conditions.

By contrast, the cost to ratepayers of accepting Calpine's offer of the PPA and acquisition for the Osprey Facility are fully known at this time. The acquisition price is set; the annual costs of the PPA are set; the operational heat rate and performance of the facility through the term of the PPA is guaranteed; additional variable costs associated with fuel transportation and operations and maintenance are known; and the condition of the plant – and its ability to operate reliably and at a high level of availability – have been demonstrated and established through operating experience.

This difference in risk profiles is an important consideration both from the perspective of risks borne by ratepayers, and from the perspective of how fairly resources have been compared in this docket. In effect, the Commission knows now with certainty what ratepayers will pay over time for power from the Osprey Facility, what performance Calpine is obligated to provide from the perspectives of capacity availability and operational performance over the term of the PPA, and what to expect in terms of plant operations and performance once the Osprey Facility is acquired by DEF. Also, as discussed in Section IV below, CC generation is a less risky proposition from a long-term market perspective because it more effectively hedges against uncertainty related to environmental policy, fuel price forecasts and longer-term market trends due to the fundamental difference between CC and CT units in terms of unit efficiency; that is, CC units like Osprey simply burn less fuel and emit lower quantities of pollutants per unit of energy generated.

In short, compared to DEF's proposal to construct the Suwannee CTs, from the perspective of ratepayers, Calpine's Osprey proposal can be viewed as a low-risk proposition that hedges ratepayer risk, via the terms of a binding, guaranteed contract with a firm acquisition price, to the maximum extent possible. In my view, this constitutes a meaningful difference in proposal attributes and allocation of risk, which should be factored into the Commission's decisions about which offers provide the best "price" and "value" to ratepayers.

Q: Did DEF evaluate any risks in its analysis?

A: DEF did not incorporate any consideration of self-build risks in its baseline evaluation of proposals in this procurement. Consequently, DEF's presentation of best-estimate CPVRR results of competing proposals – and its conclusion that the best option for ratepayers is the self-build proposal – are based on an evaluation process that does not factor in ratepayer risks. However, DEF does evaluate the potential impact of various risks in a modeling sensitivity. In Exhibit BMHB-9, Mr. Borsch presents the results of a sensitivity analysis related to construction cost risks, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks tied to the Suwannee and Hines projects. The result shows the self-build option incorporating potential downside project development and construction risks has a negative CPVRR of $167 million, relative to the base case. As I discussed in Section III.C above, this assessment is independent of the CPVRR adjustments I have made for the Osprey PPA/acquisition, which accounts for the current and known value of the Osprey acquisition price, updated transmission cost estimates, and sensitivity to gas transportation costs.

IV. CALPINE'S OFFER PROVIDES SUBSTANTIAL BENEFITS RELATIVE TO ALTERNATIVES FROM RELIABILITY, FLEXIBILITY, AND ENVIRONMENTAL PERSPECTIVES

Q: Are lower costs and reduced cost-related risks the only benefits of the Osprey Facility compared to the Company's self-build alternative?

A: No. Calpine's Osprey Facility – when compared to DEF's self-build alternative – provides a number of additional benefits not fully captured in LCOE or CPVRR analyses from the perspectives of power system reliability, flexibility, and environmental impacts. These are important considerations for the Commission at a time of significant uncertainty and change in the electric sector, with highly uncertain growth in peak load and energy consumption, pending and emerging federal requirements related to the air, water, and solid waste impacts of electric generating facilities, and significant developments in the pricing and transportation of natural gas (for heating, process needs, and power generation).

Q: Please describe the benefits of Osprey's more efficient CC capability relative to the CT capability of Suwannee.

A: To a certain extent, the LCOE and CPVRR analyses described above can reveal how the greater efficiency of CC technology (compared to CT technology) can provide benefits to DEF's system from a total production cost perspective. Yet there are a number of additional benefits of CC technology that flow from the greater efficiency of CC technology (compared to CT technology) tied to the roles that such facilities play in system operations. CT capacity is effective in providing capacity at times of system peak or otherwise when stressed system conditions require operation of peaking capacity. When committed, CT units can also provide load-following services to help the system operator meet instantaneous and longer-term variations in system load.

However, the contribution of CTs to load following and to otherwise helping manage variations in system conditions is restricted by the limited hours in the year that it is efficient to commit and operate these units. More efficient CC capacity is simply available far more to help meet system needs across a wider range of hours and system load conditions. As an efficient CC unit, Osprey would be able to help DEF meet customer demands in baseload, cycling and peaking modes. Further, Osprey would be available to provide load-following or reserve services across many more hours of the year, and under a greater variety of system load/generation configurations. For example, Osprey would likely be operating for well over 6,000 hours at various levels of output in the year to help meet system needs, compared to on the order of 1,000 hours or less for the Suwannee CTs operating at 10 percent capacity factor.

Q: Are there ancillary system benefits for DEF associated with the Osprey PPA/acquisition?

A: Yes. As noted earlier, and described in the testimony of John Simpson, the acquisition of the Osprey Facility will involve the construction of the "direct connect" transmission project, which will allow access to and availability of the full capability of the Osprey Facility in all hours of the year, and will address all system upgrade needs on DEF or third-party systems to ensure continued reliable operations. In addition, the direct connect transmission infrastructure will provide additional reliability benefits to the systems of DEF and the broader FRCC. Simpson Direct at 15. In contrast, selecting the Suwannee CTs will not involve any beneficial transmission system upgrades and will, in fact, require the retirement of existing generating capacity at the Suwannee location in order to accommodate interconnection of the new peaking facilities. Simpson Direct at 16-17.

Thus, by selecting Calpine's offer for the Osprey PPA/acquisition, DEF will (a) obtain a resource and system upgrades that can meet its stated resource needs at a cost that is in the best interest of ratepayers, (b) will do so in a way that will improve system reliability through strengthening transmission infrastructure, and c) access available efficient CC capability that can operate and contribute to system operations in far more hours of the year than the Suwannee CTs.

Q: Would acquisition of Osprey help DEF manage load and resource uncertainty in the coming years?

A: Yes. In Section III above, I describe my findings with respect to the relative cost benefits of DEF accepting Calpine's PPA/acquisition offer for the Osprey Facility. However, in addition to being a better deal for ratepayers at the outset, the Osprey PPA/acquisition would offer DEF important option value with respect to major future capital investments to meet customer needs over the next several years.

Q: Please explain what you mean by "option value."

A: Yes. In my view, there is a relatively high degree of uncertainty with respect to growth in DEF's system peak load and annual energy requirements in the coming years. While the coming retirements on DEF's system do appear to create a need for new capacity in the latter half of this decade, the magnitude and timing of that need are strongly dependent on (1) the quantity of capacity added in early years, (2) the actual level of peak load and annual energy growth compared to forecast quantities, and (3) the timing of retirement additions and resource additions. In this context, there is a potentially high "option value" in actions or decisions that can delay major capital investments.

By way of example, it is my understanding that the current air permits at Crystal River 1 and 2 allow the units to remain in operation through 2020, under the Mercury and Air Toxics Standard ("MATS") compliance limit using the site-wide averaging provision and activated carbon injection systems at CR4 and 5. Order No. PSC-14-0173-PAA-EI, Docket No. 130301-EI at 3. Delaying investment in (and recovery in rates of) the Citrus County CC units by just one year could mean $59 million in CPVRR benefits for ratepayers, even while accounting for the increased O&M expenses necessary to operate Crystal River with new pollution controls in place. (In this estimate, I did not, however, include any additional costs for changes in the 1-hour National Ambient Air Quality Standard ("NAAQS") for sulfur dioxide ("SO_2") emissions or 316(b) mitigation, as discussed in DEF responses to the Office of Public Counsel First Set of Interrogatories, Served July 1, 2014. In my view it remains unclear whether an additional year of operation would require additional significant costs beyond operational changes). Furthermore, the reliability concerns associated with outages or reductions related to CR4 and 5 that might impact the site-wide emissions averages may be reduced under a scenario with the full energy output of both Osprey and Hines available in 2019.

While this exercise means little if demand growth, retirement, and the timing of resource additions are known with certainty at this time, it can mean a great deal for ratepayers when, as now, the Company is proceeding with a major infrastructure turnover over a relatively short period of time.

Q: Why do you believe the Osprey PPA/acquisition could provide some option value for DEF and its ratepayers?

A: The Osprey PPA/acquisition may provide option value in the context of a combined view of both the pre-2018 procurement and post-2018 (i.e., the Citrus County CC units), in that it represents a resource (1) that is in operation, with no uncertainty regarding commercial operations, capabilities, or ability to contribute to system operations; (2) that is large enough to meet system needs through 2017 and possibly longer depending on how load and resource outcomes compare to current projections and plans; and (3) in combination with the construction of the Hines Chillers, could allow for some period of delay in the construction of the Citrus County CC capacity if peak load and annual energy requirements do not grow as fast as currently forecast by DEF.

Q: Have you concluded that the Company's forecasts of load/energy growth or the timing of resource addition and attrition are wrong?

A: No, I have not. The Company, the Commission, and stakeholders have all worked over the past several years to understand the potential timing of resource changes and the potential that changing economic factors will lead to rates of growth in peak load and energy requirements that depart from recent experience. I am not suggesting that the Commission second-guess those planning efforts. However, based on my experience over decades as a utility regulator and consultant, I recognize that the type of resource and forecast assumptions that go into the Company's determination of resource needs are just that – assumptions – and are almost certain to deviate from what actually transpires in the coming years. The Commission has recognized this fact in its ten-year site plan reviews, finding that in recent years, the absolute average error in retail energy sales forecasts has increased to almost 20 percent, and that even the best forecast errors have ranged between 1 and 3 percent. Review of the 2013 Ten-Year Site Plans, For Florida's Electric Utilities, Florida Public Service Commission, October 2013 at 20. Compounded over several years, these deviations can lead to significant variations in actual demand.

In consideration of this, any resource decision that has the potential to delay major investments can save ratepayers money in the long run, and thus provide an option value that should be considered in resource decision making. In the context of the pre-2018 resource need, Osprey provides some flexibility around the timing of commercial operation of the Hines Chillers projects. In the context of the post-2018 resource need, Osprey provides some flexibility around the timing of the Citrus County CC units.

Q: What do you conclude based on your consideration of these factors in the context of this procurement?

A: Based on my review of these factors, I believe that a decision by the Commission to require that DEF accept Calpine's offer for the Osprey PPA/acquisition could provide substantial option value benefits for DEF's ratepayers, and introduces a key element of flexibility for DEF as it embarks on a major period of infrastructure turnover over the next several years. As noted above, I do not believe that considering this benefit is necessary to conclude that the Osprey proposal is the best deal for ratepayers. However, the potential for option value benefits increases the advantage of selecting the Calpine proposal in the pre-2018 procurement.

Q: Do you believe acquisition of the Osprey Facility – compared to the Suwannee CTs – can provide other benefits from a public policy perspective?

A: Yes. I believe that selecting Osprey in this acquisition would allow DEF and the State of Florida to capitalize on the wide-ranging human health, climate risk mitigation, and environmental benefits that flow from using an already-built and operational, efficient, and low-emitting (in terms of emissions per megawatt-hour) resource instead of a (by comparison) relatively inefficient and higher-emitting Suwannee CT project – one that while on an existing site, would still involve new construction activities. The relative impact of CT versus CC technologies from an emission perspective is presented in Exhibit No. __ (PJH-8).

This exhibit shows emission rates from each unit proposed in this solicitation on a pounds per MWh ("lb/MWh") basis. In other words, the exhibit provides a true apples-to-apples environmental comparison of the projects with respect to the level of emissions that result from production of an equivalent amount of energy. The emission rates for the Osprey Facility are lower than the Suwannee CTs by [redacted]b/MWh, or 33 percent for nitrogen oxides (NO_x), and [redacted]/MWh or 42 percent for CO_2. These emission rates are primarily a direct function of the relative energy efficiency (i.e., heat rates) of the respective projects; in simple terms, using less fuel per MWh results in less air pollution per MWh generated. In addition, by adding the Osprey CC resource at this time, DEF may realize additional emission reduction benefits to the extent that Osprey displaces output from less-efficient existing fossil-fueled resources on the DEF system.

V. CONCLUSIONS

Q: In your opinion, does DEF's self-build plan, i.e., constructing the Suwannee CTs and the Hines Chillers, represent the most cost-effective alternative for Duke's customers?

A: No, DEF's self-build projects are not the most cost-effective alternatives for DEF and its customers. I come to this conclusion because I find that DEF's modeling and analysis occur largely within a black box, appear to be oversimplified and structurally biased from a production cost benefit perspective, and inherently – and inappropriately – favor the Company's self-build alternative. A more careful, common-sense review of the drivers of ratepayer impact associated with the various options reveals that by moving forward as proposed by DEF, DEF's ratepayers will likely incur significant additional costs and risks than they would if instead of building the Suwannee CTs, Calpine's offer is accepted. Based on my estimates presented above, Calpine's value from a ratepayer perspective is at least a $133 million benefit relative to DEF's self-build proposal, it and could be significantly greater to the extent that the Company's self-build alternative ends up more expensive than current estimates.

Q: In your opinion, is the acquisition of the capacity of the Osprey Facility, through the combination of a 5-year PPA followed by direct acquisition of Osprey by DEF, as proposed to DEF by Calpine, a more cost-effective alternative for Duke's customers?

A: Yes, it is. I come to the conclusion that selecting Osprey is the best outcome for ratepayers based on (1) a fully transparent comparison of the levelized costs of various alternatives; (2) a recalculation of cumulative present value revenue requirements starting from DEF's own calculations, with just a few reasoned adjustments reflecting current conditions and correcting for mistakes in the original analysis; (3) a review of the lack of transparency and apparent flaws in DEF's modeling approach and documentation; and (4) consideration of the nature and characteristics of risks born by ratepayers under DEF's self-build proposal, compared with selecting Calpine's offer.

Q: In your opinion, did the Company adequately consider the relevant and significant non-cost factors associated with an acquisition of the Osprey Facility?

A: No, they did not. I find that selection of Calpine's proposed PPA/acquisition of the Osprey Facility would provide a number of additional benefits from the perspectives of power system reliability, flexibility, and environmental impacts. Specifically, I identify additional benefits that include (1) the relative value of more efficient combined cycle capacity (like the Osprey Facility) – compared to combustion turbine-only capacity – to meet DEF's changing resource needs and system conditions across multiple operating modes (baseload, intermediate, and peaking); (2) the option value provided by the higher capacity of the Osprey Facility compared to the Suwannee CTs, which would allow for greater flexibility for DEF to alter the timing of major new capital investments in future years (such as the proposed Citrus County facility) should load growth and/or resource availability deviate from current expectations; and (3) the wide-ranging human health and environmental benefits that flow from using the already-built and operational, efficient, low-emitting (in terms of emissions per megawatt-hour) Osprey capacity instead of the new-construction, relatively inefficient, and higher-emitting Suwannee CTs.

Q: Considering the results of the LCOE analysis, CPVRR analysis, and additional non-cost factors that you have identified in your testimony, what should DEF have done with respect to Calpine's proposals?

A: Considering both the economic results and the numerous additional factors that are not directly related to costs and cost-effectiveness, I believe DEF should have accepted – and should now accept – Calpine's offer.

Q: **In your opinion, what action should the Commission take with respect to DEF's Petition?**

A: The Commission should deny DEF's Petition. Calpine has made an offer to DEF that represents a low-cost, low-risk, reliable, efficient, and environmentally-responsible resource choice. DEF's analysis of alternatives fails to appropriately capture these many value streams, overstates the value of their own self-build alternative (in particular the Suwannee CTs), and understates the value of the Calpine offer. A reasonable evaluation of these alternatives, a common-sense comparison of facilities' levelized costs, and a review of important reliability, health, environmental and policy factors suggests that the best option for DEF's ratepayers would be for DEF to accept Calpine's offer.

Q: **Does this conclude your testimony?**

A: Yes.

BY MR. WRIGHT:

Q Just for clarification for all of the parties, some of your testimony is confidential, correct?

A Correct.

Q Thank you. Did you also prepare and cause to be prefiled in this docket eight exhibits numbered in your testimony as exhibits PJH1 through PJH8?

A Yes.

Q Thank you.

MR. WRIGHT: Mr. Chairman, I will just note for the record, those have been marked as Exhibits 73 through 80 on staff's comprehensive exhibit list.

CHAIRMAN GRAHAM: Duly noted.

MR. WRIGHT: Thank you.

BY MR. WRIGHT:

Q Mr. Hibbard, will you please summarize your testimony?

A Sure.

Good afternoon, Mr. Chairman and Commissioners. My name is Paul Hibbard. I am Vice-President with a consulting firm headquartered in Boston called Analysis Group, Inc. We are an economic strategy and policy consulting firm.

I testify before you today having spent

roughly half my career in public service. Part of that time working for my state's Department of Environmental Protection, and the rest of the time working for the public utility commission. Most recently as chairman of the Commission from 2007 to 2010. In that capacity, I also represented the state on the energy facilities citing board in regional and national committees focused on interstate electricity and natural gas issues.

I have testified before other state commissions, before FERC, state legislatures and the U.S. Congress on issues related to electricity and natural gas policy. The other half of my career, roughly half of my career I have spend as a consultant on economic strategy and public policy in the both electricity and natural gas industries.

With respect to my testimony in this docket, I am providing testimony that relates to the option value of selecting Calpine's Osprey facility, compared to the company's Suwannee facility in the little GBRA docket.

Broadly speaking, what I highlighted for the Commission is that the larger size and more diverse operational capabilities and characteristics of the Calpine facility, the combined cycle facility, again, as compared to the Suwannee facility, would give the company more flexibility to manage longer term uncertainties in the evolution of its system. That's the sum of essentially what I am testifying to with respect to this docket.

And that concludes my summary, and I look forward to any questions you might have.

MR. WRIGHT: We tender Mr. Hibbard for cross-examination.

CHAIRMAN GRAHAM: Oakie-doke. Mr. Hibbard, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Mr. Rehwinkle.

MR. REHWINKLE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. REHWINKLE:

Q Good afternoon, Mr. Hibbard. Charles Rehwinkle. I am just looking at your testimony on pages 41 and 42. And on those pages, you discuss briefly the Citrus County unit that is the subject of the 140110, correct?

A Correct.

Q You haven't -- I didn't hear you change in your -- I didn't hear you, in your summary, change your testimony in any way; correct?

A I did not.

Q So your testimony on these two pages is the

same now as it was before your -- the party you represent entered into a deal with Duke, is that correct?

A My testimony is the same, yes.

Q Thank you.

MR. REHWINKLE: No further questions, Mr. Chairman.

CHAIRMAN GRAHAM: All right. Shady Hill.

MS. SHELLEY: No questions. Thank you.

CHAIRMAN GRAHAM: PCS.

MR. BREW: No questions. Thank you.

CHAIRMAN GRAHAM: NRG.

MS. RULE: Thank you. No questions.

CHAIRMAN GRAHAM: FIPUG.

MR. MOYLE: We do have questions.

CROSS EXAMINATION

BY MR. MOYLE:

Q Good afternoon.

A Good afternoon.

Q In your summary, you said -- I think you referenced the Suwannee facility and you didn't reference the Citrus County facility. But as Mr. Rehwinkle points out, your testimony is equally applicable the Citrus County Combined Cycle facility, correct? I mean, it's the same testimony in both

dockets?

A It's the same testimony in both dockets.

Q Yeah. Okay. And I just want to explore a little bit. I mean, do you have information about this deal that was announced?

A I do not.

Q So given that you don't, isn't, admittedly, it's hard to know whether, not knowing the parameters of the deal, whether it may change your view of the world?

A My testimony relates to the offer that Calpine played to Duke on the 3rd, that was represented in Todd Thornton's testimony. My assumption is that the deal, if anything, got better, but the answer to your question is that I don't have the details of what was offered.

Q Yeah. No, I understand. And you spent a lot of your testimony talking about flexibility, and I would think that, depending on when Duke is going to acquire the Calpine unit, that that would maybe impact your view with respect to saying, well, that gives them more flexibility, good, or less flexibility, not so good; is that fair?

A I would expect that the timing is an important factor in that, yes.

Q Okay. And with respect to flexibility -- you have been here all day, correct?

A I have been in the room most of the day, yes.

Q Okay. And in your sense of the world, in terms of flexibility, is if -- I am going to state it and you tell me if I got it right -- is if you can retain flexibility as a commission -- you are a former commissioner out of where? Massachusetts, right?

A Correct.

Q And you have testified in front of Congress. You have been well versed in public policy related utility planning, is that right?

A Yes.

Q If you, as a commission, can retain flexibility, be nimble, keep your powder dry, not fully commit to a, you know, $1.5 billion spend, that you ought to try to do that if you can; correct?

A Well, just --

Q If could you answer yes or no, and then clarify, that would be helpful.

A Well, partly yes. I just want to clarify that what I am testifying to in my testimony is that, when comparing the Calpine facility, which is a combined cycle facility, with the Suwannee facility, my testimony was that that offers some option value, in the sense that it's a larger facility and has more diverse operational characteristics.

Q Well, you didn't limit your testimony just to the Suwannee facility, did you?

A My testimony is suggesting that, compared to the Suwannee facility, Calpine's facility offers greater option value. It has a better risk profile.

Q But that's also true with respect to the Citrus County facility as well?

A I was not comparing the Calpine facility to the Citrus County facility.

Q Well, then I am confused by your testimony.

A I am more than happy to answer any specific questions.

Q Sure. Why don't you go to page 43, line 21. You state, quote, "In the context of the post-2018 resource need, Osprey provides for some flexibility around the timing of the Citrus County CC units."

A Correct. The selection of the Osprey facility compared to the selection of the Suwannee facility in the mini GBRA docket provides flexibility around the timing of the Citrus County.

Q Okay. And is it your understanding that that's been done now?

A That what's been done?

Q That there has been a selection of the Osprey facility, at least tentatively?

A   I am aware from this morning that the parties have reached tentative agreement.

Q   Okay. So if we got that tentative agreement and it comes to fruition, which I think will be determined later, but if you assume it is, then what's the flexibility around the timing of the Citrus County units that you are referencing?

A   Again, what I was doing was comparing the Osprey facility to the Suwannee facility. In my view, the larger size of the Osprey facility, combined with the different operational capabilities of the facility, offered some flexibility to the company with respect to managing uncertainties in the future evolution of the system. So, for example --

Q   Such -- yeah, just give me such as.

A   Well, let me just give you an example. If the company's load forecast is greater than they expected, the larger size of the Osprey facility would allow -- would provide some flexibility to the company compared to a smaller generating facility.

Q   So Osprey gives them more flexibility because it's how many more megawatts?

A   I believe it's on the order of 150 megawatts or so.

Q   So up on line 17, you said, "In consideration

of this, any resource decision that that has the potential delay major investments can save ratepayers money in the long run, and thus provide an option value to be considered in resource decision making."

I assume there, because you are talking about delay major investments, you were referencing the 1.5 billion Osprey facility; is that right?

A Well, I don't need to be that specific --

Q I am sorry, 1.5 billion Citrus County. I said Osprey mistakenly.

A My testimony doesn't need to be specific. Obviously, if the facility is -- any facility that has the potential to help delay major investments on behalf of the company is a good thing. And that's the value -- the option value that I thought Osprey had compared to the Suwannee facility.

Q So when you used the term major investments there, you weren't necessarily focusing on the Citrus County 1.5 billion?

A Obviously, to the extent what the company does now can delay investment in Citrus County, that could potentially provide benefits to ratepayers.

Q In your opinion, does this tentative deal provide flexibility and a possible option to defer the construction of the combined cycle unit from 2018 until

the latter point in time?

A   Again, I am not trying to be difficult, but my testimony is that, compared to Suwannee, the Osprey facility's characteristics and size provide some option value to the company.

Q   Didn't you actually do some calculations on how much ratepayers might save if the unit were deferred?

A   Well, I provided an example of the time value of money of deferring the Citrus County facility for one year.

Q   And why did you do -- why did you provide that information?

A   To provide an example to the Commission of what it was I was referring to when I suggested there could be some option value.

Q   Okay. So when you were clarifying what the option value might be, you used an example of deferral, correct? A deferral of one year?

A   I made a calculation of what the difference from the standpoint of the time value of money was in delaying the construction of the Citrus County facility by one year.

Q   Right. And how much was that?

A   I believe it was on the order of 58 or 59 million dollars.

Q And what are you referring to?

A I apologize, I am having trouble finding the number. On page 41, starting at line 12, I state that "delaying investment (in and recovery in rates of) the Citrus County CC units by just one year could mean 59 million in cumulative present value requirement benefits for ratepayers."

Q And if you delayed it for two years, you would get close to doubling that number from, call it 60 to 120, is that correct?

A The time value of money for two years, the calculation would be essentially the same. It would be a little bit less for the second year due to the discount rate; but, yes, it would be on the order of 60 million.

Q Okay. And then three years would be on the order -- I mean, it would be 60 one year -- 60 the second year, 120 in -- 60 the third year, give or take, you know, 180 if my math is right, six times three; right?

A Well, 59 the first year. It would be less than 59 the second year but not horribly less, and in the third career it would be less than that.

Q Would it be over 150 million?

A That would be my guess.

Q So I will take that as a yes.

A I am happy to go back and do the calculation if you would like.

Q I don't think it's necessary as long as we can agree it's in the neighborhood of 150 million, unless it would take you a quick time to do the calculation.

A No. The neighborhood of 150 sounds right.

Q Yeah. And the reason that you, just to make sure I am clear, that you suggested that delay might be appropriate is, in your testimony up above, you, I guess, did something to find out that Crystal River Units 1 and 2 have current air permits that allow the unit to remain in operation through 2020; is that right?

A I am not -- I don't quite understand the question you are asking.

As part of this, I wouldn't have gone through the exercise of calculating, by way of an example, what the time value of money was of delaying for one year if I didn't think that current air permits would allow the facility to be operating for that extra year.

Q Sure. And I am just exploring, because I asked you three years, and I just want to establish for the record that your testimony, you said, on line eight and nine and 10, that your understanding, quote, "it's

your understanding that current air permits at Crystal River 1 and 2 allow the units to remain in operation through 2020;" correct?

A That's my understanding from review of that docket, yes.

Q So you reviewed the docket. Is that where you got your information?

A It's in the cite right after the sentence.

Q Did you look at the DEP permitting files on this or just the Commission permitting -- just the Commission file?

A I did not look at the DEP permitting files.

Q Okay. And so just so the record is clear, my three-year calculation would comport with what you observed in looking at the docket, that Crystal River 1 and 2 can stay in operation through 2020; correct?

A Again, my understanding is based on that cite, and what it says in line nine is that, my understanding, based on reviewing that document, is that they are able to remain in operation through 2020.

Q Did you -- in part of your economic analysis, did you look and see how much of Crystal River Units 1 and 2 had been depreciated?

A No.

Q Did you -- you have an understanding they are

old units, correct?

A   I am aware of that. Yes.

Q   So given your experience as a regulator, wouldn't you expect most of that to be depreciated?

A   I would want to know. I would want to look and see where it is in the depreciation cycle.

Q   Do utilities in Massachusetts have the ability to earn a return on their invested capital? Is that the same as in Florida?

A   Yes.

Q   Okay. And so if you had a situation where you had, say, Crystal River Units 1 and 2 that were on the books at not much money, that they had been fully depreciated, or close to being fully depreciated, and you substituted a new combined cycle $1.5 billion plant, the economics, as it relates to shareholders, would be better for the new combined cycle at 1.5 billion, you would earn a return on 1.5 as compared to earning a return on depreciated book value of old coal units; correct?

A   Utilities in Massachusetts are not allowed to earn generation, but the larger the rate base the larger the return that the utility will earn.

Q   So that would be a yes?

A   I don't know. You seem like you asked several questions in that. I was trying to answer what you were getting at without going through several more questions.

Q If you were an executive for a utility and somebody said to you, here is two options, you can -- you can -- they both generate essentially the same amount of electricity from a shareholder perspective, you can have one that's in rate base 1.5 billion or one that's in rate base for 100 million, which one would you take, all other things being equal?

A If I am a shareholder of a utility, I want my rate base to be as large as possible.

Q And if you -- my question was, you are an executive for a utility. Same answer, right?

A No. I would think an executive of a utility has other obligations.

Q Fair enough.

MR. MOYLE: If I could just have a minute.

BY MR. MOYLE:

Q You say on line 44 -- on page 44, line seven, that picking up the Calpine's Osprey plant gives you a key element of flexibility as they embark -- we talked about on the main infrastructure.

You would agree that flexibility would be reduced if this commission decided to go ahead and grant the need determination for the Citrus County Combined

Cycle plant in 2018 without allowing for any flexibility or changes that may occur in load, growth or distributed energy, things like that, correct?

A Again, Mr. Moyle, just please keep in mind when I answer the question, I am comparing Suwannee to Osprey here. And what I am testifying to is that the Osprey facility, compared to Suwannee, provides option value that the Commission should consider. And that option value is valuable depending upon any number of uncertainties in the system, whether it be delay in generation, attrition of generation that exists that was unexpected, load growth that's higher or lower than you expected. I think the point of option value, in considering option value with respect to a resource selection is really to manage any number of uncertainties in the system over time.

Q And just -- final point. Part of the reason you want to do that is because it's hard to look beyond the horizon to look into the future. Assumptions change. Projections change. You know, while you are giving your best effort at it now, there is a pretty high likelihood that it's not going to be correct at the end of the day, correct?

A I would think if any of us could predict the future, we wouldn't be sitting here right now.

Q So you would agree with my statement, right?

A Yes, I would.

Q Okay. Well, listen, since I might have made you miss your flight back home to Massachusetts, I apologize if you did. Hopefully you can still get out of here, but thanks for taking some time to answer my questions.

A You are welcome.

CHAIRMAN GRAHAM: SACE.

MR. CAVROS: No questions, Commissioner. Thank you.

CHAIRMAN GRAHAM: Staff.

MR. LAWSON: No questions. Thank you.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Balbis.

MR. WALLS: Excuse me.

CHAIRMAN GRAHAM: Sorry. Do you have a question?

MR. WALLS: Would you like for me to go now or --

COMMISSIONER BALBIS: Go ahead, please.

CROSS EXAMINATION

BY MR. WALLS:

Q Good afternoon, Mr. Hibbard --

COMMISSIONER BALBIS: Mr. Chairman, I did have

a question when it's appropriate.

BY MR. WALLS:

Q And we have met before, right?

A We have.

Q Okay. Now, I want to turn back to your questions Mr. Moyle was asking you about the $59 million calculation you reference on page 41 that you call it the time value of money. And what you did there is, right, you looked at simply the benefit of just pushing back, in a net present value basis, the money spent on Citrus one year, right?

A Correct.

Q And what you didn't do is actually perform any analysis of the costs and benefits of making that decision of deferring the Citrus unit one year beyond 2018, right?

A I looked only at that value of money.

Q And you would agree with me that there are emerging federal requirements related to air, water and solid waste impacts that do affect the operation of Crystal River Units 1 and 2 beyond 2018?

A Yes.

Q And you didn't take those into account when you did your analysis about the extension of the Crystal River Units 1 and 2 beyond 2018, right?

A Other than that the only calculation I did was to add $2 million in 2018 for O&M costs for Crystal Units 1 and 2. To the extent that includes the cost of emission controls, then they would be embedded in that number. But, no, I did not specifically look at specific emission control requirements and try to estimate what the additional costs would be in that year for those units, other than whatever is embedded in that O&M number.

Q And you understand that the need for the Citrus Combined Cycle Plant includes the retirement of the Crystal River coal Units 1 and 2 in 2018, and you are not disputing the retirement of those units in that year, right?

A Correct.

MR. WALLS: No further questions.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Actually, Mr. Chairman, my questions were already asked and answered.

CHAIRMAN GRAHAM: Okay. Redirect?

MR. WRIGHT: I think one question, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. WRIGHT:

Q Just so the record is clear, Mr. Hibbard, you

were asked a question by Mr. Moyle and also by Mr. Walls about your time value of money analysis. Did that address only the capital costs of Citrus -- or Citrus 1?

A It was a full estimate of the -- it essentially represents the deferral associated with the capital costs of the new Citrus units by one year.

Q Thank you.

MR. WRIGHT: That's all I had, Mr. Chair.

CHAIRMAN GRAHAM: Mr. Wright, were you going to entered any of these exhibits or not?

MR. WRIGHT: Yes, sir. We would move Exhibit 73 through 80 into the record.

CHAIRMAN GRAHAM: Exhibits 73, 74, 75, 76, 77, 78, 79 and 80, is that correct?

MR. WRIGHT: Yes, sir.

CHAIRMAN GRAHAM: Not 81, two or -- 81 or two?

MR. WRIGHT: No. I think those are Mr. Simpson's exhibits.

CHAIRMAN GRAHAM: I am sorry.

MR. WRIGHT: That's okay.

CHAIRMAN GRAHAM: I looked past.

MR. WRIGHT: And if I may be so bold, I would ask that Mr. Hibbard be excused.

CHAIRMAN GRAHAM: Mr. Moyle, are you ready for that?

MR. MOYLE: I am good. Thank you.

CHAIRMAN GRAHAM: Mr. Hibbard, thank you very much. Have safe travels.

THE WITNESS: Thank you, Commissioners.

(Witness excused.)

CHAIRMAN GRAHAM: All right. We are close to our two-hour market for my court reporter's fingers, so we are going to take about a 10-minute break.

MS. RULE: Actually, Chairman, I am going to ask that we take a longer break. Mr. Pollock is not here. He expected 10 witnesses ahead of him and a contested hearing. He is on a plane tomorrow morning.

CHAIRMAN GRAHAM: So we have no other witnesses for tonight?

MS. RULE: Correct.

MR. MOYLE: We can do Borsch.

MS. RULE: Mr. Borsch is on for tomorrow morning, right?

MR. MOYLE: We can take him out of turn if you want to.

CHAIRMAN GRAHAM: We were specifically asked, unless Mr. Rehwinkle has any --

MR. REHWINKLE: I'm prepared to do him

tomorrow.

CHAIRMAN GRAHAM: What if we -- and everybody else can let me know -- if we start with him and we hold off on your testimony until all the other intervenors go? Or we can just start with him tomorrow. I mean, you are the one that had the problem. If everybody else is fine --

MR. REHWINKLE: It's what we have been relying on all day today.

CHAIRMAN GRAHAM: It's fine. You can start tomorrow, but if everybody else can go today, we will get that part done. If everybody else wants to wait until tomorrow, let me know.

MR. WALLS: Commissioners, I believe we only have two witnesses left, Mr. Borsch and Mr. Pollock. So there is a direct of Mr. Borsch, Mr. Pollock and then rebuttal of Mr. Borsch.

MS. RULE: And I can't tell you at this time what time Mr. Pollock gets in.

CHAIRMAN GRAHAM: Well, the question is, is OPC the only one that can't move forward today with Mr. Borsch?

MR. CAVROS: Commissioner, I prefer to move forward with Mr. Borsch tomorrow.

CHAIRMAN GRAHAM: Okay. No, that's fine.

MR. MOYLE: And my question was, I just wanted to make sure we were on a flight path to be done tomorrow, and it sounds like we are. Two witnesses, I mean, we should be able to get through two witnesses. That's coming from me.

CHAIRMAN GRAHAM: I was going to say, that's up to you, Mr. Moyle. I think we would have been done today.

MS. RULE: And Mr. Pollock's plane lands at 10:15.

CHAIRMAN GRAHAM: Okay. Well, I don't think we will be done with Mr. Borsch before then.

All right. Then that all being said, staff, unless there is something else that needs to come before us.

MR. LAWSON: No. I think we would just have the two witnesses. There is no other matters before us at the moment. So it's just whatever we decide to do with Mr. Borsch and, of course, Mr. Pollock, I believe, will be here tomorrow.

CHAIRMAN GRAHAM: All right. Well, then, we will recess until 9:30 tomorrow morning.

Thank you very much. Have a nice night.

(Whereupon, the proceedings were adjourned for the day at 4:50 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA R. KRICK, Professional Court Reporter, certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages, numbered 71 through 260 , are a true and correct record of the aforesaid proceedings.

I further certify that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 2nd day of September, 2014.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #EE212307
EXPIRES JULY 13, 2016