William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5662
(561) 691-7135 (Facsimile)
Will.Cox@fpl.com

December 22, 2017

-VIA ELECTRONIC FILING-

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20170225-EI

Dear Ms. Stauffer:

Pursuant to Order No. PSC-2017-0426-PCO-EI issued November 6, 2017, attached for filing in the above docket are the rebuttal testimony and exhibits of Florida Power & Light Company witnesses Dr. Steven R. Sim and Hector J. Sanchez. This letter, the rebuttal testimony and exhibits, and a certificate of service together are being submitted via the Florida Public Service Commission's Electronic Filing Web Form as a single PDF file.

Please contact me should you or your Staff have any questions regarding this filing.

Sincerely,

s/ William P. Cox
William P. Cox
Senior Attorney

WPC/msw
Enclosures

cc: Counsel for Parties of Record (w/encl.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING THE DANIA BEACH CLEAN ENERGY CENTER UNIT 7

REBUTTAL TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. 20170225- EI

DECEMBER 22, 2017

TABLE OF CONTENTS

Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following 6 exhibits that are attached to my rebuttal testimony:

Exhibit SRS-5: Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman;

Exhibit SRS-6: Commission Proceedings Approving or Applying 20% Reserve Margin;

Exhibit SRS-7: Comparison of FPL System NO_x Emissions for Resource Plans 2 and 3;

Exhibit SRS-8: Comparison of Major Drivers in DSM Cost-Effectiveness: 2014 DSM Goals Docket Inputs and Forecasts versus 2017 Inputs and Forecasts;

Exhibit SRS-9: Excerpt from Prior FPL Testimony in Docket No. 20080407-EG Regarding the Flaws in Using a Levelized Cost of Electricity Approach; and,

Exhibit SRS-10: FPL Fossil Fuel Generation Fleet Performance Improvements (1990-2016).

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony discusses and/or responds to the testimony of Dr. Ezra Hausman who is testifying on behalf of the Sierra Club in this docket.

Q. How is your rebuttal testimony structured?

A. My rebuttal testimony is structured into 7 parts. Part I provides a brief overview of FPL's filing in this docket to set the stage for examining Dr. Hausman's testimony. Part II identifies key points in FPL's filing that Dr. Hausman does not contest in his testimony. Part III discusses some of the problems in his testimony regarding such topics as reserve margin criteria, reliability, and determination of need filings in Florida. Part IV discusses additional problems with Dr. Hausman's testimony regarding his "alternative plan," the economics of that plan, his attempt to examine the "delay" scenarios, and fuel diversity. Part V offers some observations regarding his exhibits. A number of problematic statements made in Dr. Hausman's testimony that have not already been discussed are examined in Part VI. In Part VII, I summarize my reasons why I conclude that Dr. Hausman's testimony is unreliable and should not be given serious consideration in this docket.

Part I: Overview of FPL's Filing

Q. Would it be helpful to provide a summary of FPL's filing in this docket?

A. Yes. One of my impressions of Dr. Hausman's testimony is that he is trying to draw attention away from the results of FPL's analyses that show numerous and significant benefits that would accrue to FPL's customers from the addition of the proposed Dania Beach Clean Energy Center (DBEC) Unit 7 combined cycle unit. Therefore, I believe it would be helpful to summarize FPL's filing and the projected benefits of DBEC Unit 7 for FPL's customers before beginning an examination of Dr. Hausman's testimony.

Q. Would you please provide a summary of FPL's filing in this docket?

A. Yes. I will primarily focus on the resource planning aspect of FPL's filing, which can be summarized as follows:

- In mid-2016, using 2016 forecasts of load and generation, FPL projected that: (i) it would begin having system resource needs starting in 2024 and which grow significantly in subsequent years, and (ii) there would no longer be a balance between load, generation, and transmission import capability in the heavily populated and high electrical load Southeastern Florida region (consisting of Miami-Dade and Broward Counties) around the same time as the system resource need. As a result, FPL began extensive analyses in mid-2016 designed to determine the best way to address both the system and Southeastern Florida regional needs.

- In the 2016 analyses, FPL assumed 1,700 MW of additional universal solar would be sited outside of the Southeastern Florida region. This additional solar was significantly higher than the 300 MWs of universal solar FPL identified in its 2016 Ten Year Site Plan. FPL then analyzed how new combined cycle and combustion turbine unit options sited both inside and outside the Southeastern Florida region might satisfy the system and regional reliability needs. Solar and battery storage sited inside this region to support both of these reliability needs were also evaluated. FPL also evaluated demand side management (DSM), as well as new gas pipelines, and transmission facilities that would be required as a result of new generation additions and/or to increase transmission import capability into the Southeastern Florida region. In total, 33 resource plans were evaluated in the 2016 analyses.
- The key results of the 2016 analyses were that: (i) a specific new transmission line, the Corbett-Sugar-Quarry (CSQ) line, was capable of addressing the Southeastern Florida regional need through the decade of the 2020s (assuming no changes in forecasted load and/or available generation in the region), (ii) the addition of this CSQ line would allow a window of opportunity in which the existing Lauderdale Units 4 & 5 could be retired[1] and dismantled before replacement capacity in Southeastern Florida is constructed, and (iii) the projected cost of continuing to operate and maintain these existing Lauderdale units was significant.

[1] Note that the retirement of Lauderdale Units 4 & 5 would change the available generation in Southeastern Florida by removing 884 MW of capacity.

- In 2017, after a decision was made to add the CSQ line by mid-2019, FPL updated all of its key forecasts and assumptions, including the cost and performance characteristics of the resource options, and also included as an assumption FPL's current projection that an additional approximately 2,086 MW of universal solar would be implemented by 2023, representing an increase from the 1,700 MW assumed in the 2016 analyses. FPL then conducted new analyses of how best to address system resource needs while maintaining/enhancing reliability in the Southeastern Florida region. These 2017 analyses primarily focused on three resource plans that were based on the most promising resource options identified in the 2016 analysis. Plan 1 is a "status quo" scenario that assumes no retirement and continued operation of the existing Lauderdale Units 4 & 5. Plan 2 assumes retirement of the existing Lauderdale Units 4 & 5 in late 2018 and the addition of the 1,163 MW DBEC Unit 7 in mid-2022. This results in a net increase of 279 MW of generation in the Southeastern Florida region (1,163 MW of DBEC Unit 7 – 884 MW of the existing Lauderdale Units 4 & 5 = 279 MW net increase).[2] Plan 3 assumes the same retirement of the existing Lauderdale units in late 2018 as in Plan 2, but with the addition of approximately the same amount of firm capacity (approximately 1,163 MW) from a combination of solar and storage sited in the Southeastern Florida region.

[2] FPL notes that its planned addition of 2,086 MW of solar is 7.5 times greater than the net increase of 279 MW of gas-fired generation that would result from DBEC Unit 7.

- The results of the 2017 analyses were that: (i) Plan 2 featuring DBEC Unit 7 is projected to be $337 million cumulative present value of revenue requirements (CPVRR) lower cost to FPL's customers than the status quo Plan 1, and (ii) Plan 2 featuring DBEC Unit 7 is projected to be $1,288 million CPVRR lower cost to FPL's customers than Plan 3.
- In addition, the low cost DBEC Unit 7 project is projected to bring economic benefits to FPL's customers almost immediately beginning in 2018, lower system natural gas usage compared to the status quo scenario, lower system emissions, and to enhance both system and regional reliability.
- Therefore, FPL concludes that adding DBEC Unit 7 in 2022 is projected to provide a variety of significant benefits for FPL's customers, and FPL is respectfully requesting that the FPSC provide an affirmative determination of need decision for DBEC Unit 7 with a June 2022 in-service date.

Part II: Key Points in FPL's Filing That Dr. Hausman's Testimony Does Not Contest

Q. Does Dr. Hausman's testimony contest the results of FPL's analyses that show DBEC Unit 7 is projected to save FPL's customers $337 million CPVRR compared to the status quo resource plan (Plan 1) in which existing Lauderdale Units 4 & 5 are not retired and continue operating?

A. No.

Q. Does his testimony contest the results of FPL's analyses that show DBEC Unit 7 is projected to save FPL's customers approximately $1.3 billion CPVRR compared to Plan 3 that is designed to attempt to provide equivalent system and regional reliability from a combination of solar and storage resources?

A. No.

Q. Does Dr. Hausman's testimony contest the results of FPL's analyses which show that FPL's customers are projected to benefit from lower cumulative CPVRR system costs due to the DBEC Unit 7 project beginning as early as 2018, and continuing each year through the last year (2061) of the analysis period?

A. No.

Q. Does his testimony contest the results of FPL's analyses which show that natural gas usage on FPL's system is projected to be lower with the

DBEC Unit 7 compared to the status quo resource plan in which existing Lauderdale Units 4 & 5 are not retired and continue operating?

A. No.

Q. Does his testimony contest the fact that DBEC Unit 7 requires no new transmission facilities and no new gas pipelines?

A. No.

Q. Does Dr. Hausman's testimony contest the fact that the additional generation sited in Southeastern Florida as a result of DBEC Unit 7 will result in additional generation capacity sited in Southeastern Florida which will enhance both system and regional reliability?

A. No.

Q. Does his testimony contest the fact that DBEC Unit 7 is projected to lower system emissions of SO_2, NO_x, and CO_2 compared to the status quo resource plan (Plan 1) in which existing Lauderdale Units 4 & 5 are not retired and continue operating?

A. No.

Part III: Problems with Dr. Hausman's Testimony Regarding Reserve Margin, Reliability, and Need Determination Filings

Q. Did you find problems with statements made by Dr. Hausman in his testimony?

A. Yes. Exhibit SRS-5 presents a list of numerous inaccurate and/or misleading statements made by Dr. Hausman in his testimony. His problematic statements are presented on the left-hand side of this exhibit. The right-hand side of the exhibit explains why each statement is inaccurate and/or misleading. I will also be examining a number of these problematic statements in more detail in the remainder of my testimony.

Q. Does Dr. Hausman comment on FPL's reserve margin criteria?

A. He does. The following two statements from his testimony capture his view regarding FPL's reserve margin criteria:

"FPL uses extremely conservative reliability criteria. The industry standard for reliability is to have sufficient reserves to achieve a loss of load probability (hereafter, LOLP) of one day in ten years…the Company's two reserve margin criteria discussed above are more stringent – they mislead FPL to over-procure capacity that is not needed to meet the industry LOLP standard." (page 9, lines 9-15, and page 10, line 1)

and,

"I recommend that FPL take the following steps: Determine appropriate reserve margin criterion and regional resource needs using a loss-of-load probability of 0.01." (page 19, lines 6-8)

There are a number of problems with these statements. First, there is no single reliability criterion that is relied upon by all electric utilities and not all utilities utilize an LOLP criterion. Second, Dr. Hausman ignores the fact that reserve margin and LOLP reliability criteria are, by design, intended to give different perspectives of the reliability of a utility system, not to provide the same result. Third, in this statement he recommends an LOLP standard of 0.01 which is 10 times more stringent than the 0.1 day/year LOLP standard that FPL and most utilities that utilize an LOLP reliability criterion use. (However, on page 9 of his testimony, beginning on line 9, he discusses an LOLP criterion of *"one day in ten years"* which is equivalent to a 0.1 day/year value. With his two conflicting values, it is not clear what he is actually recommending.)

Fourth, he ignores the fact that FPL's reserve margin criteria have worked well in helping to ensure economic, reliable electric service for FPL's customers for almost two decades. Fifth, with these statements, Dr. Hausman is criticizing both FPL and the FPSC for the reserve margin criterion that FPL uses in its resource planning. Perhaps Dr. Hausman is unaware that FPL's 20% total reserve margin criterion was agreed to by FPL, two other Florida investor owned utilities (IOU), and the Florida Public Service Commission (FPSC) in 1999 after extensive examination of system reliability in Florida. Sixth, Dr. Hausman also appears unaware that, in the almost two decades since that decision, the FPSC has consistently stated that a determination of need docket is not the appropriate place to attempt to question a reliability criterion or to attempt a change in the criterion. Exhibit SRS-6 presents a compilation of a number of the FPSC's statements regarding this issue.

Q. Is there another problem regarding the concept of reliability in his testimony that you wish to discuss?

A. Yes. Speaking as one who has been employed by FPL as a resource planner for 25 years and who has continually interacted and collaborated with transmission system planners and system operators over that time period, I have come to appreciate the fact that consideration of the reliability of an electric utility system is not simply a matter of performing analyses on a computer and letting that be your only guide. There is the matter of actual real world experience that has to be factored into a utility's planning. This is particularly true when it comes to the experience of system operators whose job is to keep the system operating in real time 24/7 on a second-to-second basis. Lack of this type of specific, real world experience is not something one can compensate for solely through calculations on a spreadsheet or in a model. Therefore, system operator experience and guidance should never be ignored when planning a utility system.

In regard to the analyses presented in this docket, FPL's system operators provided specific guidance as to how resource plans should be designed if FPL wanted to look at scenarios of a potential one- or two-year delay in the in-service date for DBEC Unit 7, assuming that existing Lauderdale Units 4 & 5 are to be retired. Their input was essentially this: the longer FPL waits to replace the capacity that is lost by retiring the 884 MW of the two Lauderdale units, the more risk the system operators have to deal with. FPL witness Sanchez discusses in more detail the operational risks associated with retiring the Lauderdale units, then not bringing replacement capacity in-service as soon as possible. The loss of 884 MW that will result from the retirement of the existing Lauderdale units represents about 1/7 of the total generation in the vital Southeastern Florida region.

The specific guidance that FPL's system operations provided when FPL began to consider the one- or two-year delay scenarios was that FPL should delay the retirement of the Lauderdale units by the same amount of time DBEC Unit 7's in-service date is delayed in order to minimize operational risk. In other words, that guidance was that if the in-service date of DBEC Unit 7 is delayed one year from 2022 to 2023, then the retirement of the Lauderdale units should also be delayed one year from 2018 to 2019. Based on this input from FPL's system operators, FPL used this guidance when evaluating the "delay" scenarios.

However, Dr. Hausman has chosen to completely ignore this guidance from FPL's system operators. In the portion of his testimony in which he discusses the "delay" scenarios, he cavalierly assumes that no delay in the retirement of Lauderdale Units 4 & 5 is required because a reserve margin calculation doesn't show the need to delay the retirement. He summarizes his disregard for the specific guidance provided by FPL's system operators in the following statement:

"FPL imposed irrational and costly assumptions on its two "delay" scenarios." (page 14, lines 1-2)

From this statement, it is clear to me that Dr. Hausman does not appreciate in any degree the realities of operating a complex electric system or the importance and value of system operators' experience.

Q. Dr. Hausman's testimony opposes the addition of DBEC Unit 7 in 2022. Is part of that opposition driven by a projection that FPL meets its minimum reserve margin requirements in 2022?

A. Yes. Dr. Hausman's testimony contains the following statement starting on page 4 beginning on the last line on that page:

"I further find that the Company's request is premature, given its own projection of sufficient resources at least through 2024."

Q. Please comment.

A. My experience from a number of prior need determination hearings before the FPSC leads me to conclude that the FPSC considers many factors in a need determination docket and can approve a determination of need request based on considerations other than just a reserve margin projection. In fact, the FPSC has done so fairly recently when it approved FPL's West County Energy Center (WCEC) Unit 3 in Docket Nos. 080203-EI, 080245-EI, and 080246-EI. In those dockets, FPL requested a determination of need for WCEC Unit 3 with an in-service date of 2011 although there was not a projected system reliability need until 2013 – two years later than the requested in-service date. FPL projected that an earlier in-service date would reduce system fuel costs and emissions, plus allow FPL the opportunity to modernize the Riviera and Cape Canaveral plant sites.

The FPSC granted the need for WCEC Unit 3 with a 2011 in-service date (Order No. PSC-08-0591-FOF-EI). The FPSC's decision was based in part on FPL's projection of resource needs that would begin two years from the in-service date and increase each year thereafter.

Q. Does FPL's determination of need request in this docket have any similarities to the WCEC Unit 3 determination of need request and decision?

A. Yes. FPL is again requesting a determination of need for a new unit with an in-service date two years earlier than would otherwise be suggested solely by a system reserve margin calculation. In addition, FPL is again projecting resource needs that begin two years after the requested in-service date and continue to grow each year thereafter. And, similar to the WCEC Unit 3 docket, the new DBEC Unit 7 will significantly benefit FPL's customers in several ways including: (i) significant economic savings to FPL's customers in the amount of $337 million CPVRR that begin immediately, (ii) reduced system usage of natural gas, (iii) reduced system emissions, and (iv) enhanced system and regional reliability.

Part IV: Problems with Dr. Hausman's Testimony Regarding His Alternative Plan, the Economics of that Plan, the "Delay" Scenarios, and Fuel Diversity

Q. Dr. Hausman stated (on page 36, lines 13-15) that he created an *"an alternative plan"* to FPL's Plan 3. Did he?

A. No. FPL's Plan 3 is an example of a resource plan that addresses all of FPL's resource needs through the end of the analysis period (through 2061). What Dr. Hausman calls *"an alternative plan"* is merely a portfolio of solar, storage, and DSM that looks no further than the year 2026. At best, what Dr. Hausman has is one component of a resource plan, but he even labels this as an *"…illustrative example…"* (page 36, line 16).

Q. Please compare his portfolio versus the solar/storage component or portfolio in FPL's Plan 3.

A. Using nameplate values for solar and storage, a comparison reveals the following:

- In regard to universal solar, both portfolios use 433 MW of this resource. However, all of the universal solar in FPL's Plan 3 is in-place in 2022. Dr. Hausman's portfolio delays universal solar until 2024 and 2025, two and three years after they are added in FPL's Plan 3.
- In regard to distributed generation (DG) solar, both portfolios use 600 MW of this resource. FPL's Plan 3 adds DG solar in the 2018 through 2022 time frame. Dr. Hausman delays DG solar until 2025 and 2026, thus delaying DG solar additions by as much as 7 years compared to the DG solar additions in FPL's Plan 3.
- In regard to storage, FPL's Plan 3 adds 755 MW of storage in the 2018 through 2022 time frame. Dr. Hausman adds only 300 MW of storage and delays the storage additions until 2025 and 2026.

Thus both portfolios use the same amount of universal solar and DG solar, but Dr. Hausman assumes all of the solar is delayed until years later than they are added in FPL's Plan 3. Dr. Hausman assumes 455 MW less storage (755 MW in FPL's Plan 3 – 300 MW in Dr. Hausman's portfolio = 455 MW). Finally, Dr. Hausman assumes 200 MW of DSM/DR that is added over the 2021 – 2026 timeframe.

Q. What was your initial reaction to his illustrative portfolio?

A. My initial reaction was that it was certainly interesting that the Sierra Club representative was recommending a portfolio that would significantly delay the implementation of solar, and both significantly reduce and delay the implementation of storage, compared to what is assumed for solar and storage in FPL's Plan 3. This becomes even more interesting when one considers that such a delay in solar implementation would result in higher system emissions and higher natural gas usage, at least for the 2 to 7 years of delay, compared to FPL's Plan 3. Therefore, such a recommendation seems to be exactly the opposite of the Sierra Club's national effort to quickly increase the utilization of solar and storage.

Dr. Hausman's contemplated delay will also result in lower system and regional reliability for FPL's customers than would be the case with FPL's Plans 2 and 3, but these reliability impacts arising from the delay in solar and storage is given little if any consideration by Dr. Hausman in his testimony.

Q. Does Dr. Hausman explain why he significantly delayed the solar additions and reduced the storage additions in his portfolio?

A. Yes. He is attempting to lower the capital or fixed costs associated with the solar and storage additions in FPL's Plan 3 as explained in this statement of his:

"I do know that the capital costs would be many hundreds of millions of dollars less than under FPL's Plan 3 in an NPVRR basis, and <u>*could*</u> (emphasis added) *be competitive with Plan 2."* (page 39, lines 5-8)

Q. Does Dr. Hausman present an analysis of an actual resource plan, which utilizes his solar/storage/DSM portfolio, which can be compared to FPL's analyses of Plan 2?

A. No. This is evidenced by the following statement in his testimony:

"…let me say at the outset that this ('plan') is intended only as an illustrative example, and I do not claim to have thoroughly analyzed all of the reliability and feasibility aspects of this plan." (page 36, lines 15-17)

Q. His statement does not mention whether he analyzed the economics of his "plan." Did he perform an economic analysis that can be compared to FPL's Plan 2?

A. No. He performed no economic analyses. He admits this in the following statement:

"Q. Can you analyze what this illustrative plan would cost, relative to FPL's Plans 2 and 3? A. <u>*I cannot*</u> (emphasis added)*."* (page 39, lines 1-3)

Q. Has Dr. Hausman considered all of the economic and non-economic impacts to the FPL system that would result from his recommended portfolio?

A. No. Let us start by looking at a few aspects of the both the economics of FPL's Plans 2 and 3, and Dr. Hausman's portfolio, that he either overlooked or which he chose not to mention in his testimony.

First, let's review the CPVRR cost differences between FPL's Plan 2 and Plan 3. As shown in Exhibit SRS-4, page 1 of 2, of my direct testimony, the projected CPVRR fixed costs (in millions of dollars) shown on the second row of the exhibit is $9,637 for Plan 3 and $7,604 for Plan 2. Thus, Plan 3 is $2,033 million CPVRR more expensive than Plan 2 in regard to fixed costs. A similar comparison of the CPVRR variable costs for the two plans shown on the first row of the exhibit shows a $57,045 million CPVRR variable cost for Plan 3 and $57,790 million CPVRR variable cost for Plan 2. Thus, there is a $745 million cost advantage for Plan 3. The resulting net cost impact is a $1,288 million CPVRR advantage for Plan 2 versus Plan 3 as shown on the third row of the table.

A discussion that compares these different types of costs can be simplified by using approximate CPVRR values: Plan 3 is $2,000 million more expensive in fixed costs, and $700 million less expensive in variable costs, than Plan 2, thus combining to a net cost result that shows Plan 3 is $1,300 million more expensive for FPL's customers.

Even if one were to assume Dr. Hausman's *"many hundreds of millions of dollars"* in fixed cost savings could be achieved, his portfolio would have to save $1,300 million CPVRR in fixed costs just to break even with Plan 2, assuming no other changes in costs. This would represent a 65% reduction in fixed costs (1,300/2,000 = 65%). As an illustration, if the fixed costs for the solar/storage portfolio in FPL's Plan 2 averaged $1,000/kW, the average fixed costs for Dr. Hausman's portfolio would have to drop to $350/kW just to break even. However, there are at least three other aspects to this economic comparison that Dr. Hausman does not mention, and all three are automatically driven by his "delay solar and storage" recommendation.

Q. What is the first of these three economic aspects that Dr. Hausman has failed to mention?

A. His "delay" recommendation will automatically reduce the projected variable cost savings of $700 million CPVRR shown for FPL's Plan 3. Solar, far more than energy storage, is responsible for the $700 million in CPVRR variable cost savings projected for FPL's Plan 3. Therefore, significantly delaying the in-service dates of both universal and DG solar, as Dr. Hausman recommends in his portfolio, will significantly decrease the $700 million in CPVRR variable cost savings that is currently projected for Plan 3. The longer the delay in the solar in-service dates, the more the variable cost saving is decreased. Thus Dr. Hausman's idea of reducing fixed costs by delaying solar automatically results in his portfolio chasing a moving-away-from-him because the $700 million CPVRR variable cost savings value will now be significantly smaller.

Q. What is the second economic aspect of Dr. Hausman's recommended portfolio that his testimony fails to mention?

A. Dr. Hausman failed to mention that his portfolio has less firm capacity than does the solar and storage portfolio in FPL's Plan 3. As previously mentioned, both portfolios have identical MW amounts of solar, but Dr. Hausman's portfolio has 455 MW less firm capacity from storage than does FPL's Plan 3. This is partially offset by the 200 MW of DSM/DR that is in his portfolio. With FPL's 20% total reserve margin criterion, the DSM/DR has an equivalent capacity value of 240 MW (200 MW of DSM x 1.20 = 240 MW of equivalent capacity).

Thus Dr. Hausman's portfolio has 215 MW (455 MW from storage – 240 MW capacity equivalent from DSM = 215 MW) less firm capacity than does FPL's solar and storage portfolio in Plan 3. Therefore, 215 MW of additional resources will have to be added in Southeastern Florida in any resource plan that would be developed using Dr. Hausman's portfolio in order to address both system and regional reliability needs. System reserve margin analyses show that additional resources will be needed in 2027. The additional costs required to provide these 215 MW will offset some of the reduced fixed costs that Dr. Hausman would hope to receive from his portfolio. Recognizing that the additional resources would have to be sited in Southeastern Florida, and could conceivably require a new gas pipeline to be built to a site in Southeastern Florida, the cost of the additional resources could also run into *"many hundreds of millions."*

Q. What is the third economic aspect that Dr. Hausman failed to mention?

A. Assuming as a starting point that Lauderdale Units 4 & 5 are removed in 2018, Dr. Hausman's portfolio does not replace even the 884 MW of capacity in Southeastern Florida that would be removed by that retirement until at least 2026. Following the specific guidance previously provided by FPL witness Sanchez to replace the generating capacity that is removed by the retirement of the existing Lauderdale generating units as quickly as possible, Dr. Hausman's recommendation would lead to FPL delaying the retirement of these Lauderdale units at least 4 years until 2022 in order to maintain the approximately 4-year gap between capacity retirement and replacement as in FPL's Plans 2 and 3. This would lead to at least 4 more years of operational costs being incurred to keep the Lauderdale units operating. These additional fixed costs would be significant and would further offset the fixed cost reduction that Dr. Hausman would hope to receive from his portfolio.

Q. Does Dr. Hausman's testimony discuss the system emissions aspect of FPL's Plan 2 and/or Plan 3?

A. Yes. He makes the following statement in his testimony that discusses alternatives to Plan 2:

"…alternatives to DBEC…that could serve customers with…lower emissions of pollutants to the environment." (page 13, lines 10-12)

Q. What do FPL's analyses show regarding relative system emissions of Plans 1, 2, and 3?

A. In regard to Plan 2 versus the status quo scenario in Plan 1, Plan 2 is projected to result in lower system emissions for SO_2, NO_x, and CO_2. This projection is presented in FPL's response to Staff Interrogatory No. 8. In regard to Plan 2 versus Plan 3, Plan 3 is projected to result in lower system emissions for SO_2 and CO_2 than Plan 2 (but with a $1.3 billion higher CPVRR cost).

However, Plan 2 is projected to result in lower system NO_x emissions than Plan 3. That projection is presented as Exhibit SRS-7. And, as previously mentioned, Dr. Hausman's recommendation of delaying the in-service dates for solar and energy storage in his alternative portfolio would result in an increase in system emissions for SO_X, CO_2, and NO_x at least during the years of delay.

Q. Did Dr. Hausman comment on the solar and storage portfolio FPL utilized in its Plan 3?

A. Yes. His testimony included at least three statements regarding this portfolio. The first and second statements are:

"…FPL claimed that '[a]n estimated maximum projected amount of universal PV that could be sited in Southeastern Florida was selected first….However,

that is not how the resource plan is presented in SRS-3, nor is it the sequence represented in the model files…These files make clear that, in fact, Plan 3 calls for the more costly small-scale solar resources (referred to by FPL as distributed generation solar) constructed first, while the less costly universal solar is installed no earlier than the last year of resource builds in 2022." (page 25, lines 8-17)

and,

"…Plan 3 illogically schedules these resources in ways that would be… unrealistic…" (page 23, lines 16-17)

By these statements, it appears that Dr. Hausman is both confused and misses an important point. He is confused by the differences in the terms "selected" and "constructed/installed." The important point that he misses is that, in the real world, an electric utility has to consider practical constraints regarding the implementation of resource options it may include in a resource plan.

In regard to his first statement, FPL constructed its portfolio exactly as stated. FPL first selected universal solar to be included in its portfolio because it is the most economical way to utilize solar energy to serve FPL's customers. FPL identified that the maximum amount of universal solar that was projected to be able to be sited in Southeastern Florida was 433 MW based on an evaluation of potential sites for universal solar in Broward and Miami-Dade Counties. Then, recognizing that all of this solar could likely be implemented in a bit more than one year, FPL assumed that the work to construct all of the universal solar could wait until 2021 to start so that all of the universal solar would come in-service by mid-2022. This ensured that the universal solar component of FPL's portfolio was implemented in the most economical way.

Q. Is it reasonable to assume that a similar implementation schedule would work for DG Solar?

A. No. Whereas FPL would plan to implement universal solar in large 60 MW or 74.5 MW blocks, DG solar would be implemented in much smaller, 250 to 500 kW (kilowatt) sizes on commercial customers' roofs. The projected installed maximum amount of DG solar in Southeastern Florida is 600 MW. FPL estimated that it would require almost 1,900 separate installations to get to 600 MW by the same June 2022 date at which DBEC Unit 7 is projected to go in-service. This represents almost 1,900 public and/or private entities that must be identified, contacted, negotiated with regarding long-term contracts, and permits acquired before the installations can even begin.

There are also only about 1,600 days between January 1, 2018, and June 1, 2022. Therefore, even if DG solar installations were to begin on January 1, 2018, more than one DG solar installation per day would have to be completed for 1,600 consecutive days with no weekends or holidays off to meet the June 1, 2022 date. Recognizing that each DG solar installation will take a number of days or weeks to complete, FPL reasonably assumed that DG solar installations would have to begin in 2018, and continue each year until June 2022, to realistically implement 600 MW of DG solar by June 2022.

By referring to FPL's schedule as *"illogical"* in his second statement, Dr. Hausman failed to account for the practical considerations just described of how the implementation of such a large amount of DG solar could actually be performed.

Q. What is the third statement Dr. Hausman made about FPL's solar and storage portfolio in its Plan 3?

A. On page 28, lines 15-16, he makes the following statement:

"…the Company made the plan ***appear*** (emphasis added) *even more costly by building the most expensive resources early, thereby frontloading unduly high costs…"*

I have several reactions to this statement. First, in regard to the portion of the statement *"…building the most expensive resources early…"*, I just discussed that real world, practical considerations require that DG solar installations must begin in 2018 to meet that objective. Second, in regard to the portion of his statement *"…the Company made the plan* ***appear*** (emphasis added) *even more costly…"*, FPL did not make any resource option or resource plan "appear" more costly. FPL simply determined the projected costs for all of the resource plans it analyzed, then compared those costs. That Dr. Hausman does not like the outcome of the economic analysis does not change that fact.

Third, his use of the term "*frontloading,*" plus the overall tone of the statement, appears designed to give the impression that FPL is anti-solar. Such an impression is hard to reconcile with the fact that FPL is actively developing a very large amount of solar in Florida where it is cost-effective to do so. This is shown in the resource plans FPL developed and analyzed for its filing in this docket. In Plan 2, the addition of DBEC Unit 7 in 2022 will result in a net increase of 279 MW of gas-fired capacity (1,163 MW of DBEC Unit 7 – 884 MW of retired Lauderdale Units 4 & 5 = 279 MW).

However, as previously mentioned, a base assumption for all of the resource plans analyzed in FPL's 2017 analyses is a projected addition 2,086 MW of nameplate solar by 2023 which is 7.5 times as much net additional solar capacity as net additional gas-fired capacity. Clearly, rather than being anti-solar, FPL is a strong proponent of solar when and, most importantly, where it is projected to be cost-effective.

Q. In his testimony, does Dr. Hausman appear to recognize the fact that DBEC Unit 7 is significantly, and perhaps uniquely, advantaged by its specific location in Southeastern Florida?

A. No. This specific gas-fired generating unit has no incremental costs for land, new transmission, new gas pipeline, additional firm gas transportation, or water due to both its location at an existing generation site and its design. As a result, the projected costs of this particular gas-fired unit are very low, making it a very tough resource option to beat economically – and a very good opportunity with which to lower costs for FPL's customers, as well as lower emissions, lower system natural gas usage, and enhance system and regional reliability.

Q. Is there anything else from a comparison of solar and DBEC Unit 7 that also impacts the economics of these two types of options in these specific analyses?

A. Yes. In regard to universal solar facilities, the cost of land for FPL's 2017 and 2018 SoBRA projects was discussed in the recent SoBRA docket (Docket No. 20170001-EI). Staff Interrogatory No. 60 in the SoBRA docket inquired about the cost of land for these projects. FPL's response to this interrogatory showed that for 7 of the 8 projects that would be sited on land that FPL did not already own, the total land cost was approximately $29.8 million dollars or approximately $4.25 million per site on average for the 7 sites. Recognizing that each site will be used for 74.5 MW of solar, this works out to a land component cost of approximately $57/kW ($4,250,000 / 74,500 kW = $57/kW).

The land cost picture is much different in Southeastern Florida. The projected costs of the universal solar sites in Southeastern Florida assumed in Plan 3 ranges up to approximately $34 million per site. Thus the projected land cost for just one SoBRA-sized universal site in Southeastern Florida can be higher than the combined costs for all 7 of the previously mentioned universal solar 74.5 MW SoBRA sites located outside of Southeastern Florida. Stated in terms of $/kW, this works out to a land cost component of universal solar in Southeastern Florida of up to approximately $450/kW ($34,000,000 / 74,500 kW = $456/kW). This is roughly 8 times higher than the land component cost for the same amount of universal solar sited outside of Southeastern Florida in this year's SoBRA filing.

To summarize, the DBEC Unit 7 is significantly advantaged by its location at the existing Lauderdale plant site in Southeastern Florida, and its design is such that it requires none of the incremental infrastructure costs that new gas-fired generating units might typically require. Conversely, universal solar sited in the Southeastern Florida region is significantly disadvantaged by its location, compared to universal solar sited in most of the rest of FPL's service territory, in particular by the much higher land costs in the region compared to land costs outside of the region.

This points out that the locational aspect of any DBEC versus solar comparison is of significant importance. Furthermore, it seems reasonable to assume that land costs in Southeastern Florida may increase in the future, which would further disadvantage Dr. Hausman's recommendation to delay the implementation of universal solar in Southeastern Florida.

Q. Does Dr. Hausman's testimony address DSM?

A. Yes.

Q. Does Dr. Hausman's testimony appear to accept the fact that the cost-effectiveness of DSM on FPL's system continues to decline?

A. It is hard to say from his testimony. It contains no statement to that effect, but also contains no statement to the contrary such as: 'DSM is more cost-effective, or as cost-effective, today as it has ever been.'

Q. What is the status of DSM cost-effectiveness on FPL's system?

A. As stated in my direct testimony, DSM cost-effectiveness on FPL's system has been declining for a number of years and continues to decline. The reason for this is that the costs of key components of FPL's system that make up the bulk of DSM's avoided cost benefits have been declining. These include: fuel costs, environmental compliance costs, and costs of combined cycle generation. In addition, the fuel efficiency of the FPL system continues to get better, in part due to the implementation of solar at locations that allow solar to be cost-effective, which further lowers avoided fuel and environmental compliance costs.

In the last DSM Goals docket that concluded in late 2014, the FPSC set DSM Goals for incremental DSM signups that were approximately 50 MW per year. This was based in large part on the projected cost-effectiveness of DSM at that time. Exhibit SRS-8 presents a comparison of key cost components from the 2014 DSM Goals docket compared to current projections of those components. As shown on this exhibit, the DBEC Unit 7 is significantly less expensive to build and operate than the combined cycle unit used as the avoided unit in the 2014 DSM Goals analyses. In addition, forecasted fuel and environmental compliance costs are also significantly lower as shown in the exhibit. As a consequence, the projected cost-effectiveness of DSM has declined since FPL's DSM Goals were last set.

Q. Did Dr. Hausman have any comments about any specific resource plans that were analyzed in FPL's 2016 analyses but which were not analyzed in FPL's 2017 analyses?

A. Yes. On page 27, beginning on line 7 of his testimony, he states the following regarding FPL's 2017 analyses:

"…FPL failed to assess alternate plans including solar without storage, even though such a plan was among the four most economic plans in FPL's 2016 analysis.[53] *FPL further affirmed that the* <u>only reason</u> (emphasis added) *that the Company added storage to Plan 3 was an attempt to mimic the characteristics of DBEC – and not to address any identified reliability need."*

In this statement, Dr. Hausman is referring to Plan 3 of Iteration 3 of FPL's 2016 analyses. That plan featured 433 MW of universal solar, plus 550 MW of DG solar, for a total of 983 MW of solar which is all sited in Southeastern Florida. That plan also assumed that the existing Lauderdale Units 4 & 5 would continue to operate for the duration of the analysis period.

Q. In making this statement, did Dr. Hausman overlook anything?

A. Yes. Dr. Hausman overlooked at least a couple of items. First, because a number of forecasts and assumptions (such as load forecast, generation capacity ratings, etc.) all changed as FPL began its 2017 analyses, none of the 33 plans analyzed in 2016 could have been brought into the 2017 analyses intact without modifying each plan. Therefore, this particular plan could not have been brought over intact into the 2017 analyses. Second, one of the updated assumptions in 2017 was that the costs to continue to operate the existing Lauderdale Units 4 & 5 were projected to be $861 million CPVRR. Thus a similar plan to this Plan 3 from the 2016 analyses, or any other plan that assumed that the two Lauderdale units continued to operate, would now have to include this very significant cost. Although FPL did consider creating a similar plan for the 2017 analyses, the $861 million CPVRR cost that would have to be accounted for in that plan convinced FPL to seek a potentially more economic approach that could provide FPL's customers with similar system and regional reliability levels as FPL's Plan 2 featuring DBEC Unit 7 in the 2017 analyses.

Third, in regard to the portion of his statement that reads: "*…admitted the only reason…storage was added*", that is not exactly what I said at this deposition. I did not use the phrase "the only reason". In fact, on lines 22 – 24 on the same page of my deposition, I stated: "We had run out of PV that was considered to be doable/reasonable in Southeast Florida and turned to storage". In the earlier Iteration 1 and 2 analyses in 2016[3], FPL had already determined that the remaining roughly 700 MW of additional capacity needed to match that provided by DBEC Unit 7 would have incurred hundreds of millions of dollars CPVRR of new gas pipeline costs if such a large amount of capacity sited in Southeastern Florida were gas-fired.

For these reasons, FPL was interested to see how storage, combined with solar, all sited in Southeastern Florida, would fare in the 2017 analyses with updated costs for both solar and storage.

Q. Dr. Hausman's testimony addressed the evaluation of scenarios that examined a one- or two-year delay in the in-service date of DBEC Unit 7. Please comment on his handling of the DBEC "delay" scenarios.

A. Roughly midway through his testimony, Dr. Hausman makes the following statement about the DBEC "delay" scenarios which he refers to as Plans 4 (a one-year delay) and 5 (a two-year delay):

"<u>All of the additional costs</u> (emphasis added) *found in Plans 4 and 5, relative to Plan 2, stem from FPL's choice to delay the retirement of Units 4 and 5 by one or two years, and not from any delay in DBEC's in-service date."* (page 22, lines 1-3)

[3] This information is presented in the PowerPoint presentation that summarized the results of the 2016 analyses. This presentation was discussed in both of the depositions of me that have been occurred before this rebuttal testimony is being filed, and was attached in redacted form to Dr. Hausman's testimony as Exhibit EDH-17.

However, on page 35 of his testimony, Dr. Hausman introduces his Table 1. In his table, he categorizes 3 different types of cost impacts: (i) *"Delay Construction of Dania Beach Unit 7,"* (ii) *"Delay Retirement of Lauderdale Units 4 & 5,"* and (iii) *"Non-Unit Specific."* Thus Dr. Hausman's table, which clearly shows three types of cost impacts, contradicts his earlier statement that there is only one type of cost impact.

He then describes the result that he believes his Table 1 shows as follows:

"Table 1 also shows that, contrary to Dr. Sim's assertion, <u>FPL's analysis</u> (emphasis added) *finds that delaying DBEC by one or two years would actually save customers $33 million or $63 million dollars, respectively."* (page 34, starting on line 21 continuing to page 35, line 1)

This statement contradicts what is clearly shown by Table 1. If one properly accounts for all three types of cost impacts, his table shows that a one-year delay will cost FPL's customers about $11 million CPVRR and a two-year delay will cost FPL's customers about $38 million CPVRR (which is essentially what FPL has previous stated: approximately $12 million higher CPVRR costs for a one-year delay and approximately $38 million higher CPVRR costs for a two-year delay).

So how does he get to the $33 million and $63 million “savings” values in his statement? It is simple. Dr. Hausman just decided to leave out the second and third types of cost impacts in his arithmetic.

Regarding the second type of cost impact, he chose to completely ignore the specific guidance provided by FPL’s system operators to delay the retirement of Lauderdale Units 4 & 5 by the same amount of time that DBEC Unit 7’s in-service date would be delayed in order to minimize system operations risk. FPL’s analyses of the “delay” scenarios have followed that guidance. But Dr. Hausman chose to ignore that guidance and, consequently, he did not include the $33 million (for a one-year delay) and $74 million (for a two-year delay) of additional operating costs for Lauderdale Units 4 & 5. Perhaps Dr. Hausman chose to ignore the guidance from FPL’s system operators because he thought his simple reserve margin calculation trumped decades of system operations experience. This is not a prudent assumption to make when the one who is offering specific guidance has the responsibility for operating an electric utility system as does FPL witness Sanchez. I view this as an error on Dr. Hausman’s part.

In regard to the third type of cost impact, he chose to not include the system fuel penalty in his arithmetic. However, a system fuel penalty would automatically occur by not operating the Lauderdale units for an additional year or two, thus requiring other, more expensive units to make up the MWh that the Lauderdale units would have supplied if they had not been retired for an additional one or two years. This error in logic is hard to explain because these costs are right there on the table he created. Perhaps this is a simple mistake, or else Dr. Hausman just wanted as big a "savings" number as he could conjure up, and this was a way to get there.

Q. Do you have any other comment about Dr. Hausman's discussion of the DBEC "delay" scenarios?

A. Yes. My other comment refers to Dr. Hausman's labeling of his arithmetic as *"FPL's analysis"* in the emphasized portion of his comment above. In no way does this represent FPL's analysis. He started with FPL's analysis, then threw out two of its three parts.

Q. Did he make just this one claim that his calculation was "FPL's analysis"?

A. No. He makes similar statements towards the end of his testimony:

"Building DBEC in 2022 is clearly not the most cost-effective alternative, as <u>the Company's own analysis</u> (emphasis added) *establishes…"* (page 42, lines 22–23)

and,

"…customer interests would be better served if the FPL (sic) delayed the project not only for the one or two years <u>that FPL's analysis shows</u> (emphasis added) *would save customers money…"* (page 43, lines 2-4)

Because he threw out two of the three parts of FPL's analysis, what he presents is by definition not *"FPL's analysis"*. At best, perhaps he was just imprecise in his choice of words (although he uses them repeatedly).

Q. Does Dr. Hausman comment on DBEC Unit 7 in regard to system fuel diversity?

A. Yes. He makes a number of comments regarding the DBEC unit and FPL system fuel diversity. Here are a few:

"Nor has FPL shown that DBEC promotes fuel diversity in Florida or in FPL's generating fleet". (page 6, lines 2-3)

and,

"Further extending the Company's reliance on a single…fuel…" (page 41, line 12)

Q. Are his comments consistent with the facts in this docket?

A. No. It is well known that natural gas is the fuel that FPL system most uses to produce electricity and that DBEC Unit 7 will utilize natural gas as its primary fuel. However, the very fuel-efficient heat rate of the 1,163 MW DBEC Unit 7 will result in significantly reducing the operating hours of other, less fuel-efficient gas-fired generating units on FPL's system as DBEC Unit 7 is operated instead. As a result, DBEC Unit 7 is projected to reduce system natural gas usage compared to the status quo resource plan (Plan 1). This decreases the percentage of FPL's energy mix that is fueled by natural gas, thus improving fuel diversity on FPL's system. This point was made in my direct testimony, and the projection of the system natural gas usage for both Plans 1 and 2 were presented in response to Staff Interrogatory Number 15. Thus, contrary to Dr. Hausman's statements, DBEC Unit 7 will enhance fuel diversity on FPL's system and will not extend/increase FPL's reliance on natural gas.

Part V: Observations Regarding Dr. Hausman's Exhibits

Q. Did you or your staff review the exhibits that Dr. Hausman attached to his testimony?

A. Yes. Dr. Hausman's 44-page testimony was accompanied by approximately 580 pages of exhibits. Exhibit EDH-1 was Dr. Hausman's resume. Exhibits EDH-2 through EDH-13 can be generally described as press releases regarding utility contracts and reports that present the results of various studies. Dr. Hausman's name does not appear as an author on these reports, so it appears he did not perform any of these studies. In that sense, these exhibits appear to be an aggregation of news reports and studies done by others. The rest of his exhibits, EDH-14 through EDH-23, are excerpts from the Sierra Club's depositions of me, documents from FPL's response to discovery in this docket, and excerpts from FPL's 2017 Site Plan and the FPSC's review of Florida utilities' 2017 Site Plans.

Q. In Exhibits EDH-2 through EDH-13, how many of these hundreds of pages appear to pertain specifically to FPL and its system of generation and transmission?

A. None.

Q. Did any of these exhibits pertain to any Florida utility?

A. Yes. Exhibit EDH-3, consisting of a total of only 4 pages, pertained to the Jacksonville Electric Authority (JEA). The key point from this exhibit is presented on page 17, lines 7 through 9, of Dr. Hausman's testimony. In that excerpt, JEA representatives are quoted as stating:

"…the price of utility-scale solar PPAs has declined from $75/MWh on average in 2016 to near JEA's current fuel charge of $32.50/MWh today."

Dr. Hausman then draws the following conclusion:

"In other words, below the cost of fuel for gas-fired generation, indicating that solar PPAs are already competitive with new and even existing gas-fired generation." (page 17, lines 9 through 11)

Q. What is your reaction to this?

A. I have two reactions. First, although JEA did not specify what *"near"* to the $32.50/MWh value means, it appears safe to assume that the solar PPA values they are examining are higher than the $32.50/MWh value. Second, Dr. Hausman did not take the logical next step and compare the $32.50/MWh value to the fuel-based $/MWh cost of the specific gas-fired generator that is the topic of this docket: DBEC Unit 7. Had he done so, using information already produced in the docket [(i) the forecasted FGT firm gas cost for the year 2022 utilized in FPL's 2017 analyses, and (ii) the full load heat rate of 6,119 BTU/kWh], the calculation would be: $3.74/mmBTU gas cost x 6,119 BTU/kWh x 1,000 kWh/MWh = $22.89/MWh. This DBEC-based value for 2022 is 30% lower than the $32.50/MWh value for 2017 quoted in Dr. Hausman's statement.

In addition, a check was made using FPL's UPLAN model to see how long it would be until FPL's system average fuel cost was projected to climb to the $32.50/MWh level. The projection was that this cost would not be reached until 2036, almost 20 years from now. If Dr. Hausman's objective was to use a *"near"* to $32.50/MWh value to show how competitive solar PPAs were becoming, it appears his unfamiliarity with FPL's system, especially in regard to how much more fuel efficient FPL's system is than most utilities, resulted instead in his testimony showing how much lower the cost of a solar PPA, particularly one in which the solar facility was sited in Florida, would have to drop to match the fuel-based cost of DBEC Unit 7 and the FPL system.

Q. Did Dr. Hausman's testimony discuss $/MWh values elsewhere in his testimony?

A. Yes. On page 16, starting on line 13, of this testimony, Dr. Hausman makes the following statement:

"For example, NEER recently announced a PPA with Tucson Electric Power delivering a combined solar and storage solution for under $0.045 per kWh, with solar portions priced at under $0.03 per kWh. This would be cost competitive with or superior to new gas-fired resources on a levelized cost basis."

Q. What is your reaction to this?

A. I was surprised that Dr. Hausman believes that a levelized cost-based comparison of resource options can provide meaningful results. Such a comparison almost invariably ignores a number of significant system cost impacts that must be accounted for in order for obtain a complete picture of the economics of resource options. Consequently, an attempt to use a levelized $/MWh cost approach for comparing resource options will almost certainly yield meaningless results.

It is for this reason that neither FPL, nor the FPSC, utilizes a levelized cost of electricity (also commonly referred to as a "screening curve") approach to make final resource decisions. FPL has addressed this topic at least twice before in DSM Goals and nuclear cost recovery dockets before the FPSC. For example, a portion of my rebuttal testimony from the 2009 DSM Goals docket (Docket No. 20080407-EG) discussed the fundamental flaws in attempting to compare resource options on a levelized $/MWh approach. That discussion is provided as Exhibit SRS-9.

Q. Even if one were to ignore the problems with Dr. Hausman's attempt to use levelized cost numbers, how meaningful is it to try to compare cost values of solar in Arizona to cost values of solar in Miami-Dade and Broward Counties?

A. It is not meaningful. If the same project were to be replicated in Florida, the cost would be significantly higher for several reasons. One of these reasons is that solar insolation in the dry Arizona climate is higher than in humid, cloudy Florida. As a result, the projected annual capacity factor for the solar component of the Arizona project could be expected to be approximately 35%. By comparison, the projected annual capacity factor of FPL's' 2017 and 2018 SoBRA facilities is approximately 27%. Thus, the Arizona solar project will have an annual MWh output that is 30% higher than Florida's SoBRA facilities (35 / 27 = 1.30). Another of these reasons is that the Arizona project had zero land costs. This $0/kW land cost component is significantly lower than the up to $450/kw land cost component previously discussed for universal solar in Southeastern Florida.

For reasons such as this, the same project installed anywhere in Florida, not even in the more expensive Southeastern Florida region, would have a $/MWh cost significantly higher than the cost for the Arizona project. This is yet another example of why the location of where a solar facility is placed has to be a significant consideration.

Part VI: Other Problematic Statements Made in Dr. Hausman's Testimony

Q. Exhibit SRS-5 presents a listing of inaccurate and/or misleading statements made by Dr. Hausman in his testimony. Are there any of these problematic statements that you would like to discuss outside of that exhibit?

A. Yes. There are eight such statements that I have not already addressed, but which I will discuss in this section of my rebuttal testimony. The first of his statements refers directly to the DBEC unit:

"…more effectively advanced through reliance on technology that is not <u>reliant on imported fuel</u> (emphasis added)*…"* (page 43, lines 13-14)

The phrase "imported fuel" is typically used to refer to fuel that is imported from a foreign country into the U.S. The new DBEC Unit 7 will run on natural gas delivered by the existing FGT pipeline which provides natural gas which is all produced in the U.S. Thus, this statement of Dr. Hausman is, at best, puzzling.

Q. What is the second of these statements that you will discuss?

A. Dr. Hausman's testimony includes the following Q & A:

"Q. Has FPL explained its use of GRM as an additional reliability criterion? A. No, FPL has not." (page 8, lines 12-13)

FPL has explained its use of the GRM reliability criterion in numerous recent Ten Year Site Plan filings and briefly discussed it again in FPL's 2017 Ten Year Site Plan. In addition, FPL's development and use of the GRM criterion was recently discussed in detail in FPL's testimony in the Okeechobee combined cycle need determination docket (Docket No. 150196-EI). More importantly for this docket, the GRM criterion did not play a significant role in the analyses which led to the selection of DBEC Unit 7 as the best choice for FPL's customers. FPL's system resource needs projected with using both the 20% minimum total reserve margin criterion and the 10% minimum generation-only reserve margin (GRM) criterion were very similar to the system resource needs projected if only the 20% minimum total reserve margin criterion were used. This is shown in Exhibit SRS-2.

Q. What is the third statement?

A. This statement is:

"FPL can even meet its reliability needs via additional transmission…" (page 12, lines 1-2)

In this section of his testimony, Dr. Hausman was discussing both FPL system and Southeastern Florida regional reliability needs. Although additional transmission can (and will - courtesy of the CSQ line) assist with meeting the Southeastern Florida regional need, it cannot by itself meet FPL system resource needs. Transmission lines move electricity from one location to another location, but transmission alone does not result in additional generating capacity for FPL's system that can address system resource needs. Furthermore, an individual transmission line is limited in regard to the total amount of capacity and energy it can transport, regardless of the magnitude, or type, of generation that it has access to. If even more capacity and energy need to be transmitted to a region, then new transmission lines, and their costs, will be needed.

Q. What is the next statement?

A. There are two related statements that deserve attention. Both refer to Dr. Hausman's opinion that FPL's customers will unnecessarily face higher costs if DBEC Unit 7 is brought into service in 2022.

"…deferring, reducing, or even avoiding expensive supply-side generation additions, protecting them from <u>*overpaying now*</u> (emphasis added)*…"* (page 12, lines 13-14)

and,

"…FPL would needlessly place DBEC in service …even though <u>*there is no reliability or cost benefit to doing so*</u> (emphasis added)*."* (page 21, lines 1-3)

The *"overpaying now"* comment in the first statement is not consistent with the facts of this docket. In Exhibit SRS-4, page 1 of 2, the CPVRR results of the economic analyses of Plans 1, 2, and 3 are shown. Plan 2 is projected to result in FPL's customers paying $337 million CPVRR less than with the status quo Plan 1, and paying $1.288 billion CPVRR less than with Plan 3 which features solar and storage. Therefore, FPL's customers are projected to pay significantly less on a long-term CPVRR basis with Plan 2 which features DBEC Unit 7.

On page 2 of 2 of this same exhibit, the graph shows that FPL's customers are projected to benefit almost immediately with Plan 2 compared to either Plan 1 or Plan 3. Therefore, FPL's customers are projected to pay less in the short term as well with Plan 2 which features DBEC Unit 7.

In his second statement, the *"<u>no reliability or cost benefit</u>"* comment regarding Plan 2 is also not consistent with the facts of this docket. The cost benefits of Plan 2 have just been addressed in the paragraph above. In regard to reliability, the net increase of 279 MW that will result from DBEC Unit 7 will enhance increase system reserve margins, thus enhancing system reliability. And because that net increase of 279 MW occurs in Southeastern Florida region, regional reliability will also be enhanced by DBEC Unit 7.

Q. What is the fifth statement that you will discuss?

A. Dr. Hausman's testimony contains the following statement:

"…FPL did not even seek to take advantage of improvements it expects in both the cost and performance of CC units." (page 20, lines 21-23)

By making this statement, Dr. Hausman ignores the fact that FPL is constantly seeking to improve the cost and performance of its generation fleet. Exhibit SRS-10 provides a summary perspective of the improvements FPL has made in its fossil fuel generation fleet from 1990 to 2016. As shown by this exhibit, the levels of FPL's improvements have been impressive.

Dr. Hausman is also ignoring portions of the direct testimonies in this docket of FPL witness Kingston and me. Both our testimonies point out that FPL is seeking, and will continue to seek, ways to improve the DBEC Unit 7 design, cost, and performance characteristics that were used in FPL's 2017 analyses. These efforts will continue even after an affirmative need determination decision would be received. If these improvements result in a projected lower CPVRR system cost for FPL's customers, then FPL will both inform the FPSC of the changes and projected CPVRR benefits, and will seek to incorporate the improvements into the DBEC Unit 7 design.

Just such an improvement was identified, and taken advantage of, regarding the recently approved Okeechobee combined cycle unit. FPL's need filing initially projected that unit would have a Summer peak rating of 1,622 MW. During the need determination process, the peak rating of this unit increased to 1,633 MW at no additional cost to FPL's customers. Then, subsequent to the affirmative need decision, FPL's continuing efforts to improve the design resulted in the Summer peak capacity rating increasing to 1,748 MW at no additional cost. FPL's customers will benefit from the lower system CPVRR costs that are projected to result from FPL's ongoing improvement efforts that led to these changes in the Okeechobee combined cycle unit. The DBEC Unit 7 design is similarly being examined during this need determination process, and will continue to be examined after the docket concludes, for improvement opportunities that will benefit FPL's customers.

Q. What is the sixth statement?

A. On page 19, lines 25-26, Dr. Hausman recommends that FPL should:

"Use RFPs in the final procurement process to try to reduce the cost of resources when they are ultimately procured."

By making this recommendation, it appears that Dr. Hausman does not know that this is exactly what FPL's standard practice is when it is time to ultimately procure resources. This was recently explained by FPL witness Bill Brannen in his direct testimony earlier this year in the SoBRA docket (Docket No. 20170001-EI). In his testimony, Mr. Brannen explained how FPL requested bids from numerous suppliers separately for the solar panels, the inverters, the step-up transformers, and for construction of the universal solar facilities. This was also the procurement process that FPL used for the last generating unit for which a determination of need was granted by the FPSC, the Okeechobee combined cycle unit that will be in-service in 2019. It is also the procurement process that FPL will follow if an affirmative need determination decision is granted by the FPSC for DBEC Unit 7.

Q. What is the next statement?

A. Dr. Hausman makes the following statement regarding the fact that FPL's Plans 2 and 3 are designed to have an equivalent amount of firm capacity in order to compare the economics of two resource plans, Plans 2 & 3, with equivalent levels of both system and regional reliability:

"Plans 1, 4, and 5 are not "identical" to Plan 2 in regard to annual reserve margins or regional balance, and FPL had no problem presenting an economic comparison between these plans and Plan 2." (page 24, lines 23-26)

I have two reactions to this statement. First, the Sierra Club representative is now pointing out that Plan 2 offers FPL's customers a greater level of system and regional reliability than do Plans 1, 4, and 5. And, by doing so, Dr. Hausman has contradicted his earlier statement in his testimony (that I've just discussed) in which he claims that DBEC Unit 7 offers no reliability benefits to FPL's customers. Second, FPL could have added more resources to Plans 1, 4, and 5 to make them equivalent to Plan 2 in regard to system and regional reliability. However, Plans 1, 4, and 5 are already more expensive than Plan 2 (and Plan 3 is significantly more expensive than Plan 2). The addition of more resources to Plans 1, 4, and 5 would have increased their CPVRR costs, thus resulting in these plans being even more costly than Plan 2. Thus, any additional analytical effort to make Plans 1, 4, and 5 equivalent to Plan 2 in regard to reliability to Plan 2 was unnecessary.

Q. What is the eighth statement that you wish to discuss in this section?

A. Dr. Hausman is critical of the fact that FPL did not make extensive use of one of FPL's resource planning models, the EGEAS model, in its analyses. On page 14, beginning on line 15, Dr. Hausman states:

"While FPL has routinely used the EGEAS model to develop its ten-year site plans, it did not use this model in its 2017 analyses. Moreover, in its 2016 analysis, FPL only applied the EGEAS model in the first of four iterations. FPL explains its abandonment of the model by claiming that "the need to simultaneously solve for both FPL system and SE Florida regions requires a new analysis approach."

The EGEAS model is designed to examine a relatively small number of resource options whose costs are entered as inputs to the model. Then, using these resource options, it first develops resource plans to meet predetermined system resource needs, and performs economic analyses of these resource plans.

FPL attempted to use EGEAS in Iteration # 1 of its 2016 analyses to test its usefulness in simultaneously analyzing options that could address both system and regional resource needs. We quickly found out that its usefulness was very limited for this type of analyses. In these analyses, resource options, sites, transmission plans, and gas pipelines, plus their costs, must all be accounted for. The problem is that one must first create a resource plan that selects the resource options, their sites, and their in-service dates before the transmission analyses and gas pipeline evaluations can even begin. Once the transmission and gas pipeline analyses have each been completed, any attempt to re-optimize, which would change the resource option selection, sites, or in-service dates, could invalidate the transmission and/or pipeline components of the plan.

The remaining three iterations in FPL's 2016 analyses, and the 2017 analyses, continued to pose similar challenges. Consequently, I discussed the scope of our analyses, and the difficulties we were having in trying to perform the analyses, with the developers of EGEAS. We discussed whether there were different ways to use the model to overcome the difficulties we were having. None were identified. We also discussed whether the EGEAS developers were aware of another model available on the market that could potentially perform these types of analyses. They were unaware of any model that could do so.

Therefore, FPL did not use the EGEAS model for further analyses after Iteration #1 in the 2016 analyses. FPL relied instead on an on-going collaborative effort from experienced personnel from a number of FPL departments/business units to develop the resource plans. Then the UPLAN model and FPL's Fixed Cost Spreadsheet, which FPL typically uses in its resource planning work and development of its Site Plans, were used to develop the cost projections for those resource plans.

Part VII: Summary and Conclusions

Q. Please summarize your view of Dr. Hausman's testimony.

A. I will summarize my view with the following five points:

1) In his testimony, Dr. Hausman does <u>not</u> contest the major points FPL has made in its filing regarding the addition of DBEC Unit 7 in mid-2022 which include:

- DBEC Unit 7 is projected to have lower CPVRR costs for FPL's customers by $337 million versus a status quo scenario (Plan 1) and $1.288 billion versus a plan with equivalent system and regional reliability levels that features solar and storage sited in Southeastern Florida (Plan 3);
- Cost savings to FPL's customers are projected to begin as early as 2018 and continue for the duration of the analysis period;
- DBEC Unit 7 will result in additional generation capacity in Southeastern Florida, thus enhancing both system and regional reliability for FPL's customers;

- DBEC Unit 7 will lower system usage of natural gas compared to the status quo scenario, thus improving fuel diversity on FPL's system; and,
- DBEC Unit 7 will lower SO_2, NO_x, and CO_2 system emissions compared to the status quo scenario.

Therefore, these key points of FPL's filing are unchallenged.

2) Instead, Dr. Hausman attempts to divert focus away from these projected benefits of the DBEC Unit 7 project in his testimony. However, Dr. Hausman, who describes himself as an *"…expert based on my expertise and experience in energy economics…"* (page 2, lines 8-9), performed no economic or non-economic analyses of any alternate resource plan that could be compared to the economics of Plan 2 which features DBEC Unit 7.

3) Instead, he merely discussed one *"illustrative"* component of a resource plan. Regarding this component, he states that, in his opinion, this potentially *"could"* be cost-competitive with DBEC Unit 7. However, in his attempt to explain how his component could lower fixed costs through his recommendation to delay the implementation of solar and storage, he neglected to account for the fact that this approach would result in: (i) increased system variable costs, (ii) increased fixed costs to acquire needed additional firm capacity resources, (iii) further increased fixed costs due to the need to delay the retirement of the Lauderdale units, (iv)

lower system and regional reliability, (v) increased system gas usage, and (vi) increased system emissions.

4) The only economic calculation that Dr. Hausman attempts is in regard to the economics of delaying DBEC Unit 7. However, even here he performed no original, independent analysis. Instead, he simply started with the analysis that FPL had provided and threw out two-thirds of that analysis. Dr. Hausman then compounds the problem with this arithmetic by repeatedly referring to his effort as *"FPL's own analysis"*. This statement in clearly inaccurate and misleading, and undermines his credibility.

5) In addition, Dr. Hausman made numerous inaccurate and/or misleading statements in his testimony. These problematic statements further undermine his credibility as a witness.

After consideration of the items listed above, I conclude that Dr. Hausman's testimony is unreliable and not worthy of serious consideration by the FPSC in this docket.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
1	4/24 - 5/3	*"I further find that the Company's request is premature, given its own projection of sufficient resources at least through 2024, … ."* **(Misleading)**	The FPSC can approve a need determination based on a number of considerations under Section 403.519, Fla. Stat., not just the projected resource need year of the utility. In fact, the FPSC approved FPL's need determination request for West County Energy Center (WCEC) Unit 3 with a requested 2011 in-service date which was two years earlier than FPL's then projected resource need date. This was based on the fact that FPL has continuing and growing resource needs and on projected benefits for FPL's customers. FPL's request for a need determination in this docket is very similar to the WCEC Unit 3 need determination request both in terms of timing of requested in-service date versus projected resource need and in terms of projected benefits for FPL's customers.
2	6/2 - 6/5	*"Nor has FPL shown that DBEC promotes fuel diversity in Florida or in FPL's generating fleet, … ."* **(Inaccurate)**	Both FPL's direct testimony and FPL's response to Staff Interrogatory Number 15 show that DBEC Unit 7 will reduce FPL system usage of natural gas. This reduction in the use of natural gas improves the fuel diversity of FPL's system.
3	8/12 - 8/13	*"Q. Has FPL explained its use of GRM as an additional reliability criterion? A. No, FPL has not."* **(Inaccurate and Misleading)**	FPL has explained its use of the GRM criterion in a number of Ten Year Site Plan filings with the FPSC and provided a detailed explanation of the development of the GRM in Docket No. 150196-EI in its rebuttal testimony. Furthermore, the GRM criterion plays an insignificant role in FPL's analyses in this docket as explained in FPL's direct testimony and as shown in FPL's responses to Staff Interrogatory Numbers 25 and 26.
4	9/9 - 9/11	*"The industry standard for reliability is to have sufficient reserves to achieve a loss of load probability (hereafter, LOLP) of one day in ten years."* **(Inaccurate and Misleading)**	There is no single *"industry standard"* reliability criterion. Different states, and even different utilities in the same state, use different reliability criteria and not all utilities even utilize an LOLP criterion.
5	9/9 - 10/1	*"FPL uses extremely conservative reliability criteria. The industry standard for reliability is to have sufficient reserves to achieve a loss of load probability (hereafter, LOLP) of one day in ten years…the Company's two reserve margin criteria discussed above are more stringent – they mislead FPL to over-procure capacity that is not needed to meet the industry LOLP standard."* **(Misleading)**	FPL did not create its 20% total reserve margin criterion on its own. It was put in place at the conclusion of extensive examination of system reliability in the State of Florida after consideration of projected reliability for individual utility systems and the FRCC. FPL, two other IOUs, and the FPSC agreed that this was an appropriate minimum planning criterion for reliability, and the FPSC has approved FPL's continuing use of this reserve margin criterion as shown in Exhibit SRS-6.
6	11/14 - 11/19	*"Q.What can FPL do to resolve or forestall its projected reserve shortfall and projected imbalance in Southeast Florida? A.FPL has many options, such as incremental additions of large-scale solar…Various energy storage technologies, including batteries, can also help meet reserve margins. ..."* **(Misleading)**	FPL examined exactly this in its Plan 3, which provided the same level of system and regional reliability in Southeastern Florida from solar and storage as does DBEC Unit 7. Plan 3 would be more costly to FPL's customers by $1.288 billion CPVRR. Despite this statement early in Dr. Hausman's testimony, he recommends later in his testimony that what is needed is to add significantly less storage and to delay the implementation of both solar and storage by a number of years compared to what FPL assumed in its Plan 3.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
7	12/1 - 12/2	*"FPL can even meet its reliability needs via additional transmission…"* **(Inaccurate)**	Two different types or perspectives of reliability are discussed at length in FPL's filing: FPL system reliability and Southeastern Florida region reliability. Transmission additions can (and do) address the Southeastern Florida regional reliability issue. However, transmission additions by themselves do not increase generating capacity and cannot address FPL system reliability.
8	12/13 - 12/14	*"…deferring, reducing, or even avoiding expensive supply-side generation additions, protecting them from <u>overpaying now</u> (emphasis added)…"* **(Inaccurate)**	FPL's direct testimony clearly shows that FPL's customers are projected to economically benefit by Plan 2 by $337 million CPVRR versus the status quo Plan 1, and by $1.288 billion CPVRR versus Plan 3. Furthermore, FPL's customers are projected to begin receiving the CPVRR benefits of lower system costs from Plan 2 beginning almost immediately (in 2018).
9	13/10 - 13/12	*"…alternatives to DBEC…that could serve customers with…lower emissions of pollutants to the environment."* **(Inaccurate and Misleading)**	Plan 2, which features DBEC, is projected to lower system SO_2, NO_x, and CO_2 emissions compared to the status quo Plan 1. Plan 2 is also projected to lower system NOx emissions compared to Plan 3 which features an equivalent amount of firm capacity from solar and storage by 2022 (DBEC's in-service date.) In addition, Dr. Hausman's recommendation to delay the in-service dates of solar and storage by a number of years from the assumed in-service dates in Plan 3 will only serve to increase system emissions for SO_2, NO_x, and CO_2 compared to Plan 3 at least during the years of delay in solar in-service dates.
10	14/1 - 14/2	*"… (iv) FPL imposed irrational and costly assumptions on its two "delay" scenarios; …."* **(Inaccurate)**	Far from being "irrational", the assumptions Dr. Hausman refers to were based on specific guidance received from FPL's System Operations group - a very rational group that is responsible for actually operating the FPL system and maintaining 24/7 reliable service to FPL's customers and through all potential events that can be foreseen.
11	14/15 - 15/1	*"While FPL has routinely used the EGEAS model to develop its ten-year site plans, it did not use this model in its 2017 analyses. Moreover, in its 2016 analysis, FPL only applied the EGEAS model in the first of four iterations. ... FPL explains its abandonment of the model by claiming that "the need to simultaneously solve for both FPL system and SE Florida regions requires a new analysis approach."* **(Misleading)**	FPL attempted to utilize the EGEAS model in the first of four iterations in its 2016 analyses. Significant difficulties were found due to the nature of the analyses being attempted. Discussion with the EGEAS developers resulted in no feasible solution to the difficulties being experienced. Nor was FPL, or the EGEAS developers, able to identify another computer program that could perform the type of analyses FPL was attempting to conduct. Consequently, a new approach to these analyses was indeed required.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
12	16/13 - 16/17	*"For example, NEER recently announced a PPA with Tucson Electric Power delivering a combined solar and storage solution for under $0.045 per kWh, with solar portions priced at under $0.03 per kWh. This would be cost competitive with or superior to new gas-fired resources on a levelized cost basis, ..."* **(Misleading)**	Dr. Hausman is stating that a comparison of different types of resource options using a levelized cost of electricity $/MWh cost perspective can produce meaningful results. This is not the case. A levelized cost of electricity approach is fundamentally flawed when comparing two different types of resource options because such an approach ignores numerous significant cost impacts to the utility system that will occur when a resource option is put in-service. In addition, Dr. Hausman is insinuating that the cost of a solar project in Arizona can be replicated in Florida. He does not take into account that there are numerous differences between the two states that will affect a $/MWh cost. These include higher solar insolation in the dry Arizona climate than in humid, cloudy Florida, and the cost of land for this Arizona project was zero compared to very high land costs in Miami-Dade and Broward counties.
13	17/7 - 17/9	*"…the price of utility-scale solar PPAs has declined from $75/MWh on average in 2016 to near JEA's current fuel charge of $32.50/MWh today."* **(Misleading)**	Dr. Hausman is attempting to compare a solar PPA price to JEA's current fuel charge on a $/MWh basis. That is irrelevant to this docket. The meaningful comparison would be to compared this $32.50/MWh price to FPL's much lower system fuel charge.
14	17/9 - 17/11	*"In other words, below the cost of fuel for gas-fired generation, indicating that solar PPAs are already competitive with new and even existing gas-fired generation."* **(Misleading)**	Dr. Hausman is attempting to compare a solar PPA price to JEA's current fuel charge on a $/MWh basis. That is irrelevant to this docket. The meaningful comparison would be to compare this $32.50/MWh price to the fuel-based $/MWh cost of the specific gas-fired generator at being discussed in this docket: DBEC Unit 7. That cost is significantly lower that $32.50/MWh.
15	19/6 - 19/8	*""I recommend that FPL take the following steps: Determine appropriate reserve margin criterion and regional resource needs using a loss-of-load probability of 0.01."* **(Misleading)**	Dr. Hausman appears unaware that for 20 years the FPSC has stated that a need determination docket is not the appropriate forum for debating a utility's reliability criteria as is shown in Exhibit SRS-6.
16	19/17 - 19/19	*"…and do not subject customers to unnecessary costs for resources long before they are needed for reliability purposes."* **(Inaccurate and Misleading)**	As clearly shown in FPL's direct testimony, the addition of DBEC Unit 7 in mid-2022 will result in lower costs for FPL's customers immediately (in 2018) and will ultimately result in a projected CPVRR savings for FPL's customers of $337 million compared to the status quo Plan 1, and $1.288 billion compared to Plan 3.
17	19/25 - 19/26	*"Use RFPs in the final procurement process to try to reduce the cost of resources when they are ultimately procured."* **(Misleading)**	Apparently Dr. Hausman does not realize that this is exactly the process that FPL uses when it ultimately procures new combined cycle units, solar facilities, etc.
18	20/21 - 20/23	*""…FPL did not even seek to take advantage of improvements it expects in both the cost and performance of CC units."* **(Inaccurate)**	The direct testimonies of two FPL witnesses (Kingston and Sim) clearly state that FPL is seeking to improve the performance, plus lower the cost, of the DBEC Unit 7 design that FPL has used in its analyses. Furthermore, these testimonies point out that FPL will continue doing so even after an affirmative determination of need decision is reached by the FPSC.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
19	21/1 - 21/3	*"“…FPL would needlessly place DBEC in service …even though there is no reliability or cost benefit to doing so (emphasis added).”* **(Inaccurate)**	FPL's direct testimony and petition clearly state that DBEC Unit 7 is projected to save FPL's customers $337 million CPVRR compared to the status quo Plan 1, and to save $1.288 billion CPVRR compared to Plan 3 which provides a comparable level of reliability as with Plan 2 featuring DBEC Unit 7. In addition, the addition of a net increase in generating capacity of 279 MW at the Lauderdale site will increase reliability for both the FPL system and the Southeastern Florida region.
20	22/1 - 22/3	*“All of the additional costs (emphasis added) found in Plans 4 and 5, relative to Plan 2, stem from FPL’s choice to delay the retirement of Units 4 and 5 by one or two years, and not from any delay in DBEC’s in-service date.”* **(Inaccurate)**	As Dr. Hausman's own Table 1 shows, there are three types of cost impacts that FPL identified in its analyses of the "delay" scenarios. Clearly the decision to delay the retirement of Lauderdale Units 4 & (based on specific guidance from FPL's system operators) is not responsible for all of the cost impacts.
21	22/21 - 23/1	*"It appears that FPL has arbitrarily and superficially tried to make its plans as similar as possible, …"* **(Inaccurate and Misleading)**	Rather than an "arbitrary" or "superficial" approach, FPL has clearly explained its approach. The addition of DBEC Unit 7 in mid-2022 will result in a specific enhanced level of both system and regional reliability for FPL's customers. The issue was whether FPL's customers could receive the same level of enhanced system and regional reliability with solar and storage instead of with DBEC Unit 7 (*i.e.* , an apples-to-apples comparison). Plan 3 was designed to deliver this same level of system and regional reliability from solar and storage as would DBEC Unit 7. The result of this apples-to-apples comparison was that Plan 3 would cost FPL's customers $1.288 billion CVPRR more than would Plan 2, which features DBEC Unit 7.
22	23/16 - 23/17	*"…Plan 3 illogically schedules these resources in ways that would be… unrealistic…”* **(Inaccurate)**	Rather than being an "illogical" schedule for solar implementation, FPL's schedule is very logical. FPL's schedule takes advantage of the fact that all 6 universal solar facilities can be built in a bit more than one year so that they are delivered in 2022 when needed, thus minimizing their fixed costs. In regard to DG solar, to implement the projected maximum of 600 MW of DG solar will require DG installations on more than 1,800 different sites. Each installation is projected to take days and/or weeks. Because there is are only about 1,600 days between January 1, 2018 and June 1, 2022, the DG solar installations must begin years before 2022. FPL notes that its schedule will still require more than one installation per day for more than 1,600 straight days.
23	24/23 - 24/26	*“Plans 1, 4, and 5 are not “identical” to Plan 2 in regard to annual reserve margins or regional balance, and FPL had no problem presenting an economic comparison between these plans and Plan 2.”* **(Misleading)**	Plan 2, which features DBEC, is already projected to have lower CPVRR costs than either Plans 1, 4, and 5. FPL could have added more resources to those plans to bring them up to an equal level of reliability, but this would only further disadvantage those plans in regard to costs. In addition, Dr. Hausman's statement contradicts his earlier statement that the addition of DBEC in Plan 2 offers *"no reliability or cost benefit of doing so". (See item # 16 above).*

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
24	25/8 - 25/17	*"…FPL claimed that '[a]n estimated maximum projected amount of universal PV that could be sited in Southeastern Florida was selected first….However, that is not how the resource plan is presented in SRS-3, nor is it the sequence represented in the model files…These files make clear that, in fact, Plan 3 calls for the more costly small-scale solar resources (referred to by FPL as distributed generation solar) constructed first, while the less costly universal solar is installed no earlier than the last year of resource builds in 2022."* **(Inaccurate and Misleading)**	Dr. Hausman is apparently confused by the terms "selected" and "constructed". Because universal solar is the most economic way to utilize solar energy, FPL looked at it first and chose the most advantageous way to schedule or construct the 6 universal facilities so that all would be in service by June 2022. Then FPL determined a practical schedule for the more than 1,800 DG solar installations that would be needed to achieve the 600 MW projected maximum of DG solar. As previously mentioned above, this required DG solar installations to begin in 2018.
25	27/7 - 27/9	*"…FPL failed to assess alternate plans including solar without storage, even though such a plan was among the four most economic plans in FPL's 2016 analysis."* **(Inaccurate and Misleading)**	Dr. Hausman is referring to Plan 3 in Iteration 3 in FPL's 2016 analyses. This plan consisted of 433 MW of universal solar plus 550 MW of DG solar. This plan was not carried forward into the 2017 analyses for two reasons. First, because of changes in forecasts of available generation, load, and transmission plans, none of the 33 plans - including this one - that were evaluated in the 2016 analyses could be brought into the 2017 analyses without changes in the plans. Second, FPL did consider creating a similar plan for its 2017 analyses that would account for the 2017 forecasts and assumptions. However, this specific plan had as a base assumption that the Lauderdale Units 4 & 5 were not retired and remained in operation for the duration of the analyses. Thus this plan would have the full $861 million CPVRR operational costs for the Lauderdale units attributed to it, thus significantly increasing its costs. This factored into FPL's decision to seek what might be a more economically competitive plan for its 2017 analyses.
26	27/9 - 27/11	*" FPL further admitted that the only reason that the Company added storage to Plan 3 was an attempt to mimic the characteristics of DBEC..."* **(Inaccurate and Misleading)**	In regard to the statement *"...admitted the only reason...storage was added",* I did not use the phrase *"the only reason"* in my deposition. In fact, on the same page of my deposition, on lines 22-24, I stated that: "We had run out of PV that was considered to be doable/reasonable in Southeast Florida and turned to storage." In the earlier Iterations 1 and 2 of the 2016 analyses, we had already determined that the remaining approximately 700 MW of capacity in Southeastern Florida needed to match DBEC Unit 7 could not be met by gas-fired generation sited in Southeastern Florida without incurring the cost of hundreds of millions of CPVRR dollars for a new gas pipeline. Thus FPL was interested to see how storage combined with solar, all sited in Southeastern Florida, would fare with both storage and solar costs updated with 2017 projections and assumptions.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
27	28/15 - 28/16	*"…the Company made the plan appear (emphasis added) even more costly by building the most expensive resources early, thereby frontloading unduly high costs…"* **(Inaccurate and Misleading)**	FPL's analyses did not make any plan "appear" more or less costly. FPL analyzed all of the resource plans on a consistent and equal basis to determine their projected costs. Dr. Hausman simply does not like the outcome of that analysis. In addition, Dr. Hausman again describes inaccurately how FPL determined the schedule for solar implementation that is part of FPL's Plan 3. As described in several of the items above, the schedule simply takes into account practical considerations of how 6 universal solar projects, and more than 1,800 DG solar projects, would likely be implemented to complete all installations in approximately 1,600 days.
28	34/21 - 35/1	*"Table 1 also shows that, contrary to Dr. Sim's assertion, FPL's analysis (emphasis added) finds that delaying DBEC by one or two years would actually save customers $33 million or $63 million dollars, respectively."* **(Inaccurate and Misleading)**	Dr. Hausman's arithmetic is not "FPL's analysis". He started with FPL's analysis and threw out two of the three parts of FPL's analysis. Consequently, what he shows cannot be FPL's analysis. In throwing out those two parts, Dr. Hausman makes both an error in judgement and a logical error.
29	39/5 - 39/8	*"I do know that the capital costs would be many hundreds of millions of dollars less than under FPL's Plan 3 in an NPVRR basis, and could (emphasis added) be competitive with Plan 2."* **(Misleading)**	Dr. Hausman's statement is misleading because any move to reduce fixed costs for solar and storage by his recommendation to significantly delay solar and storage implementation will have other impacts on system costs. As a result of his delay recommendation, system fuel costs will be higher, additional resource will need to be procured which increases fixed costs, and additional operational costs for the Lauderdale units, which will need to remain in operation for more years, will also be incurred. Thus Dr. Hausman's statement ignores many other system cost impacts that will increase as a result of his recommendation.
30	40/15 - 40/17	*"FPL should also consider…transmission upgrade options that could increase its import capability into the region."* **(Misleading)**	FPL did analyze transmission system enhancements and/or additions that would be needed for the resource plans analyzed for this filing. This is discussed in FPL's direct testimony and is also clearly shown in the PowerPoint presentation that explains FPL's 2016 analyses and was provided in response to Sierra Club discovery.
31	40/24 - 40/25	*"I do not agree that DBEC is an effective way to enhance FPL's fuel diversity … ."* **(Misleading)**	By this statement, Dr. Hausman is accepting the fact that the addition of DBEC Unit 7 will enhance FPLs' fuel diversity. With his acceptance that DBEC Unit 7 enhances fuel diversity, he is contradicting his earlier statement in item # 2 above in this listing of Inaccurate and Misleading statements.
32	41/12	*"Further extending the Company's reliance on a single…fuel…"* **(Inaccurate)**	The addition of DBEC will lower FPL's system usage of natural gas as explained in FPL's petition, direct testimony, and response to Staff Interrogatory Number 15. As a consequence, FPL's reliance on natural gas is lowered, not increased or extended.
33	42/22 - 42/23	*""Building DBEC in 2022 is clearly not the most cost-effective alternative, as the Company's own analysis (emphasis added) establishes…"* **(Inaccurate and Misleading)**	Dr. Hausman's arithmetic is not "FPL's analysis". He started with FPL's analysis and threw out two of the three parts of FPL's analysis. Consequently, what he shows cannot be FPL's analysis.

Incorrect and/or Misleading Statements Made in the Testimony of Sierra Club Witness Dr. Hausman

	Starting Page/Staring Line	Incorrect and/or Misleading Testimony Statement	Correct Information
34	43/2 - 43/4	*"…customer interests would be better served if the FPL (sic) delayed the project not only for the one or two years that FPL's analysis shows (emphasis added) would save customers money…"* **(Inaccurate and Misleading)**	Dr. Hausman's arithmetic is not "FPL's analysis". He started with FPL's analysis and threw out two of the three parts of FPL's analysis. Consequently, what he shows cannot be FPL's analysis. In throwing out those two parts, Dr. Hausman makes both an error in judgement and a logical error.
35	43/13 - 43/14	*"…more effectively advanced through reliance on technology that is not reliant on imported fuel (emphasis added)…"* **(Inaccurate)**	DBEC Unit 7 will be fueled by the FGT pipeline, which is supplied solely by natural gas produced in the U.S. Consequently, DBEC Unit 7 will not rely on fuel imported from outside the U.S.

Commission Proceedings
Approving or Applying 20% Reserve Margin

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
981890 PSC-99-2507-S-EU	FPL, FPC, TECO	Generic Investigation	Commission approved 20% reserve margin stipulation for FPL, FPC and TECO. "During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities. … We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed."
991973 PSC-00-0504-PAA-EQ	FPC	Standard Offer	Commission granted rule waiver, in part because of 20% reserve margin standard. "If the waiver were not granted, FPC's efforts to meet the new 20% reserve margin would be frustrated."
001064 PSC-01-0029-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 2. "We find that Florida Power Corporation has a need for additional capacity to maintain the reliability and integrity of its system, as contemplated by Section 403.519, Florida Statutes. The record shows that FPC has demonstrated **a** need for additional capacity to meet its 20 percent minimum reserve margin criteria. … In Order No. PSC-99-2507-S-EU, Docket No. 981890-EU, the Commission approved the stipulation reached by the peninsular Florida investor-owned utilities (IOUs). These IOUs agreed to implement a 20 percent minimum reserve margin criteria to be fully effective by the summer of 2004. Prior to this stipulation, FPC utilized a 15 percent minimum reserve margin criteria. As shown in Exhibit 10, answers to staff's interrogatories, FPC's projected reserve margin in the winter of 2003/04 is 18.4 percent, if Hines 2 is not brought into service. FPC needs only

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			approximately 130 MW to precisely reach a 20 percent reserve margin in the winter of 2003/04. FPC will violate its 20 percent minimum reserve margin criterion, in the winter of 2004/05, if Hines 2 is delayed. FPC, therefore, is only accelerating the proposed capacity addition six months in order to meet the stipulation.”
001437 PSC-00-2434-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. “Subsequently, by Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. To achieve this goal, FPL now plans to install six CTs at Ft. Myers, which will initially operate in a stand-alone mode until the overall completion of the repowering, currently projected for June 1, 2002.”
010107 PSC-01-1337-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. “By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. However, in an effort to achieve this goal by the Summer of 2001, FPL plans to install two combustion turbines (CTs) at the Martin Site in June, 2001. These units will initially operate in a stand-alone peaking mode with planned conversion to natural gas-fired, combined-cycle generators in the 2005-2006 time period to meet FPL’s expected increased customer growth and usage.”
	FPL, FPC, TECO	2001 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted reserve margins for Peninsular Florida range from 20% to 23% during summer peak seasons, and from 23% to 26% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings.”
020262 020263 PSC-02-1743-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Martin Unit 8 and Manatee Unit 3. “We find that Florida Power & Light company has a need for additional capacity to maintain the reliability and integrity of its system, which will be provided by-

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			Manatee Unit 3 and Martin Unit 8. FPL has an estimated need for 1,122 MW of additional capacity for Summer, 2005, and an additional need for 600 MW of capacity for Summer, 2006. The 1,107 MW of summer capacity from Manatee Unit 3 will contribute to FPL's electric system reliability and integrity. With the addition of that capacity, FPL's projected reserve margin for Summer, 2005 is 19.92%. In order to precisely meet a planning reserve margin criterion of 20.0%' FPL needs only 15 MW of capacity with the addition of Manatee Unit *3* in Summer, 2005. Therefore, FPL does not have a pressing reliability need for the entire 789 MW of capacity from Martin Unit 8 until Summer, 2006. As discussed below, however, the record shows that it is more cost-effective for FPL to place Martin Unit 8 into commercial service in 2005 rather than 2006."
020295 PSC-02-0909-PAA-EQ	FPC	Standard Offer	Commission granted waiver of a Commission rule because of the need to meet the 20% reserve margin criterion. "We agree that if the waiver is not granted, FPC's efforts to meet the new 20% reserve margin would be frustrated. On November 30, 1999, we approved an agreement between FPC, FPL, and TECO adopting a 20% reserve margin planning criterion starting in the summer of 2004. A delay in the RFP process could seriously jeopardize FPC's ability to bring Hines 3 on line by the December, 2005, in-service date."
020332 PSC-02-1103-PAA-EI	FPL	Depreciation	Commission approved depreciation rates for units added by FPL to meet the 20% reserve margin criterion. "By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent beginning with the Summer of 2004. To achieve this goal in a more timely fashion, FPL installed six CTs at Ft. Myers in *2000* and 2001, initially operating in a stand-alone mode. This provided immediate increases to the FPL system. With the recent addition of the six HRSGs, Ft. Myers became a combined cycle operating facility on May 31, 2022."
020953 PSC-03-0175-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 3. "Reserve Margin PACE questioned whether there is a present need for the Hines Unit 3. PACE argues that FPC has done well over the past with a 15 percent reserve margin and if this margin is maintained, Hines Unit 3 is not needed. Regardless of past experience, however, Order No. PSC-99-2507-S-EU,issued December 22, 1999, in Docket No.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			981890-EUf requires Florida's investor owned utilities (IOUs) to increase minimum planning reserve margins to a 20% reserve margin by the summer of 2004. By approving the stipulation proposed by the IOUs and issuing the above Order, we have already determined that 20% is the appropriate reserve margin criteria, and the IOUs are required to utilize this criteria, unless modified in a subsequent proceeding. To provide reliable service, utilities are required to maintain a margin of generating capacity above the firm demand of their customers (planned reserves). At any given time during the year, some generating plants will be out of service and unavailable due to forced outages, periodic maintenance, refueling of nuclear plants, etc. Therefore, adequate reserves must be available to provide for this unavailable capacity and for higher than projected peak demand due to forecast uncertainty and abnormal weather. The proper forum to address what minimum reserves are necessary should be in a generic docket, as was previously done, and not in a particular utility's power plant need determination docket. FPC has relied heavily in the past on demand side management (DSM) to meet its reserve requirements. FPC cannot use DSM as often or with the same duration as physical generation without eventually affecting customer participation levels, as was demonstrated by FPC's customer attrition from its DSM programs in 1998 and 1999. The record indicates FPC's DSM programs are becoming less cost-effective compared to the cost of generation. For these reasons, FPC is attempting to build up its physical reserve percentage.” … “In summary, we find that FPC's load forecast is reasonable. FPC's projected reserve margin in the winter of 2005/2006 is 17 percent if Hines Unit 3 is not brought into service, and therefore FPC will violate its 20 percent minimum reserve margin in the winter of 2005/06 . FPC projects that the growth in winter peak demand will average approximately 159 MW a year from 2002/03 to 2006/07, with a projected peak in 2006/07 of 9,195 MW. FPC has projected a growth in winter peak demand of 416 MW for the period 2004/05 to 2006/07. Therefore, we find that Hines Unit 3 will be needed by December 2005, to maintain FPC’s electric system reliability and integrity.”
	FPL, PEF, TECO	2002 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			"The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 24% to 27% during summer peak seasons, and from 27% to 31% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings."
030866 PSC-03-1329-PAA-EQ	PEF	Standard Offer/ Bid Rule Waiver	Commission granted a waiver of the Bid Rule due to a likely inability to meet the 20% reserve margin criterion. "We believe that if the waiver is not granted, Progress's efforts to meet the 20% reserve margin would be frustrated. In 1999, an agreement was approved between Progress Energy Florida, Florida Power & Light Company, and Tampa Electric Company adopting a 20% reserve margin planning criterion, effective with the summer of 2004. See Order No. PSC-99-2507-S-EU, issued December 22, 1999, Docket No. 981890-EU, In Re: Generic Investigation into the Adequate Electric Utility Reserve Margins Planned f o r Peninsular Florida. A delay in the RFP process could seriously jeopardize Progress's ability to bring Hines 4 on line by the December 2007 in-service date, an action which is necessary to ensure that the Company maintains a 20% reserve margin. As a result, we agree with the Company that this potential impairment to the reliability of Progress's generation resources constitutes "substantial hardship" within the meaning of Section- 120.542, Florida Statutes."
	FPL, PEF, TECO	2003 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing."
040029 040031 040033 PSC-04-0763-PAA-EG	FPL PEF TECO	DSM Goals DSM Goals DSM Goals	Established DSM goals for FPL, PEF, and TECO using avoided costs calculated assuming a 20% reserve margin.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
PSC-04-0769-PAA-EG PSC-04-0765-PAA-EG			
040206 PSC-04-0609-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Turkey Point Unit 5. "There is a need for the proposed Turkey Point Unit 5, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Absent the timely addition of Turkey Point Unit 5, FPL's summer reserve margins will fall to 14.7 percent in the summer of 2007, well below the Commission-approved 20 percent reserve margin planning criterion. Further, the addition of Turkey Point Unit 5 will enhance FPL's operating flexibility and system reliability in Southeast Florida by reducing the growing imbalance between generation and load in this region."
	FPL, PEF, TECO	2004 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing."
	FPL, PEF, TECO	2005 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. " Based on our review, the Commission finds the Ten-Year Site Plans filed by the eleven reporting utilities to be suitable."
060225 PSC-06-0555-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County 1 & 2. "We find that there is a need for FPL's proposed West County Units 1 and 2, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Without completing West County Unit 1 by June 2009, FPL's and Peninsular Florida's electric system reliability and integrity would be significantly reduced. FPL would also fail to meet its 20 percent reserve margin planning criterion. Without the unit, FPL's summer reserve margin for 2009 would decrease to 15.5% and decrease further in each following year."
060387 PSC-06-0743-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with a renewable resource, Florida Biomass. "By the terms of the negotiated contract, the Florida Biomass combined cycle

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			generator is to be operational no later than December 1, 2009, with net output projected to be 116 MW. PEF's 2006 Ten Year Site Plan shows projected growth of approximately 200 MW of demand each year. PEF asserts that it will need additional capacity by 2009 to maintain its 20% reserve margin. The next planned unit is the Bartow Repowering Project, currently scheduled to come on line in June 2009. There are six additional units planned through 2015 to meet PEF's demonstrated need for capacity in that period. While PEF has not included the Florida Biomass contract as a firm resource in its 2006 Ten Year Site Plan, if the contract is approved, PEF will include the projected committed capacity as a firm resource."
	FPL, PEF, TECO	2006 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds them to be suitable."
070100 PSC-07-0456-PAA-EQ	FPL	Depreciation	Approved of Depreciation rates for Turkey Point Unit 5. "By Order No. PSC-99-2507-S-EU,2 FPL agreed to a minimum reserve margin planning criterion of 20 percent beginning in the summer of 2004. However, in 2003, FPL's integrated resource planning work determined that an additional 1,066 megawatts (MW) of capacity was needed by the summer of 2007. If the additional megawatts were not obtained, FPL and the Peninsular Florida's electric system reliability and integrity would be reduced and the required 20 percent reserve margin would not be met for 2007. Also, the balance between the amount of generating capacity located in southeast Florida and the electrical load would not be maintained. Pursuant to Order No. PSC-04-0609-FOF-EI,3 the Commission approved the construction of Turkey Point Unit *5* to meet FPL's needed capacity."
070602 PSC-08-0021-FOF-EI	FPL	Need Determination for Expansion	Commission granted a determination of need for expansion of Turkey Point and St. Lucie nuclear units. "There is a need for the Turkey Point nuclear power plant ("PTN") and St. Lucie nuclear power plant ("PSL") uprates, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), Florida Statutes. Without the uprates, FPL's electric system reliability and integrity will be significantly reduced, and FPL will fail to meet its 20% reserve margin beginning in 2012 ….

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			FPL has future resource needs of 490 MW of incremental capacity in 2012. All demand side management ("DSM") that is known to be cost-effective through 2013 is already reflected in FPL's 2006/2007 resource planning work, which identified this capacity need. Consequently, to meet FPL's summer reserve margin criterion of 20% through 2013, FPL needs new capacity in the form of power plant construction and or purchases."
070650 PSC-08-0237-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Turkey Point units 6 and 7. "There is a need for Turkey Point 6 and 7, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), F.S. FPL argues that there is a need for Turkey Point 6 and 7 because overall system demand is expected to grow by 40%. FPL further contends that without Turkey Point 6 and 7, the reserve margin would fall below 20% and FPL would have to rely more heavily on DSM, which would render FPL's system less reliable. … Based on the foregoing, we find that FPL's capacity need projections are reasonable. We note that no party took issue with the load forecast. FPL's need was determined after taking into account 1,899 MW of additional DSM, all other currently committed supply projects, 414 MW of recently approved nuclear capacity includes previously certified nuclear uprates in 2012 and 2013 as well as new uncertified gas CC units in 2011, 2015, 2016, and 2017, includes previously certified nuclear uprates in 2012 and 2013, but no new gas units and 287 MW of renewable generation, although none are yet contracted, from 2 biomass projects and 3 municipal waste-to-energy projects. FPL's need for additional capacity to meet rising electricity demands cannot be satisfied with additional purchased power from renewable generation. Additional DSM programs and renewables are not capable of deferring the need for additional capacity. In conclusion, the evidence shows that FPL has a need for 8,350 MW of additional capacity beginning in the 2011 through 2020 period. Turkey Point 6 and 7 will provide only a portion of FPL's need for capacity."
		2007 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Pursuant to Section 186.801, Florida Statutes, the Commission has reviewed the

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			utilities' 2007 Ten-Year Site Plans and finds them to be suitable because the plans were responsive to the energy policies in place at the time of filing."
080407 080408 080409 PSC-09-0855-FOF-EG		DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
080203 080245 080246 PSC-08-0591-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County Energy Center Unit 3, Conversion of Riviera Plant, and Conversion of Cape Canaveral Plant. "FPL has demonstrated a reliability need for additional resource capacity in 2013. Usually, when a company seeks to satisfy a need for additional resource capacity using natural gas facilities, a petition for need determination would be submitted approximately 3 years before the facility's in-service date. The company decided, however, that unique economic opportunities and site-specific circumstances made it more cost effective to build WCEC 3 for operation in 201 1 and perform the conversions at Cape Canaveral and Riviera by 2013 and 2014. FPL contends that it will not be able to perform the conversions of Cape Canaveral and Riviera without approval of the proposed WCEC 3. FPL chose gas-fired combined cycle units as its resource option to meet its capacity needs. This decision was made primarily because coal and nuclear generation have longer construction times and would not be able to provide the additional capacity in the time needed. This approach will maintain FPL's reserve margin above 20 percent throughout the period."
080512 PSC-08-0707-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with Vision/FL, LLC. "The Facility is projected to have a maximum nominal generating capacity of 50 MW. After serving internal loads, the Facility will provide firm capacity of approximately 40 MW to PEF. The expected annual energy amounts to 3 11,853 MWh. As a renewable energy resource, Vision's projected committed capacity of 40 MW will be independent **of** the current fossil fuel infrastructure as it uses a separate, distinct supply mechanism for its biomass fuel. It is noted that the addition of 40 MW of firm capacity and energy from Vision in 2010 to PEF pursuant to the contract will not completely defer or avoid the need for additional capacity in order to meet a 20% reserve margin. However, the Facility will displace energy generated by fossil fuels, reducing the state's dependence on these resources and promoting fuel diversity."

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
		2008 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2008 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes."
		2009 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the 11 reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2009 Ten-Year Site Plans filed by the 11 reporting utilities to be suitable for planning purposes."
		2010 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission finds the 2010 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes. While the plans are suitable for planning purposes, they are subject to modification due to factors such as changes to fuel cost, energy use projections, evolving technology, and shifting energy policy. Therefore, the Commission will continue to closely monitor the future rate of load growth in Florida and its effect on the need for additional generation and transmission facilities in the state."
110018 PSC-11-0293-FOF-EI	FPL	Need Determination	Commission granted a determination of need for expansion of Solid Waste Authority of Palm Beach County unit. "FPL determines the magnitude and timing of its resource needs based on a minimum reserve margin. The reserve margin represents available generating capacity during peak demand periods. FPL has established a minimum reserve margin of 20 percent above peak demand for reliability purposes. FPL has identified a reliability need beginning in 2016. This projection is consistent with FPL's 2011 Ten Year Site Plan ("TYSP"). Commencing in 2015, SW A will provide the output

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			if the Expanded Facility as firm capacity and energy to FPL. … Upon review, we find that the Joint Petitioners are persuasive in their argument that the Expanded Facility will improve electric system reliability and integrity on FPL's system. FPL is currently projecting a need for additional capacity. The Expanded Facility, projected to provide between 70 and 80 MW of firm capacity by 2015, will satisfy a portion of FPL's projected need. Therefore, the SWA Expanded Facility will contribute to the reliability and integrity of FPL's electric system. In addition to providing additional capacity, the Expanded Facility, which will be located in Southeast Florida, has attributes that will address two system concerns for FPL: a) enhancing fuel diversity; and b) maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. We find that there is a need for the SWA Expanded Facility taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, F.S.
110309 PSC-12-0187-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Port Everglades plant. "There is a need for Port Everglades Next Generation Energy Center, taking into account the need for electric system reliability and integrity. Based on the 20 percent reserve margin criterion adopted by FPL pursuant to a stipulation with this Commission, FPL projected in its filing that additional capacity to meet firm peak demand will be needed by the summer of 2016. If FPL did not construct PEEC until 2019, the Company's projected reserve margin would drop to 18.2 percent in 2017 and 2018 and would be primarily made up of Demand Side Management resources. After accounting for all projected DSM from cost-effective programs approved by this Commission, FPL' s projections at the time of the filing indicate that by 2016, the Company will have a capacity need of 284 MW in order to adhere to FPL's minimum reserve margin criterion of 20 percent. The timing of FPL's projected need was largely driven by the expiration of existing purchased power agreements totaling 1,306 MW of summer capacity and the decision to place certain units into inactive reserve mode. PEEC will provide 1,277 MW of capacity to help satisfy the Company's capacity needs through 2020."

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
	FPL, DEF, TECO	2011 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2011 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes."
120234 PSC-13-0014-FOF-EI	TECO	Need Determination	Commission granted a determination of need for Polk unit 205 conversion. "We find that there is a need for Polk 2-5 as proposed by TECO to maintain electric system reliability and integrity as this criterion is used in Section 403.519(3), F.S. For planning purposes, TECO utilizes a 20 percent firm reserve margin reliability criteria above the system firm peak demand. After taking into account load growth, existing power plant unit capacity, firm purchased power agreements, and demand-side management (DSM), TECO's summer reserve margin is projected to fall below 20 percent in 2017. By providing up to approximately 459 MW of additional capacity, Polk 2-5 will help TECO meet its needs for additional capacity beginning in 2017."
120314 PSC-13-0164-PAA-EQ	FPL	PPA Approval	Commission approved PPA agreements with U.S. EcoGen. "FPL maintains a planning reserve margin of 20 percent pursuant to a stipulation approved by this Commission.[1] FPL's next major generating additions are the Cape Canaveral Modernization (1,210 MW) in 2013, the Riviera Modernization (1,212 MW) in 2014, and the Port Everglades Modernization (1,277 MW) in 2016, followed by Turkey Point Units 6 and 7 (1,100 MW each) in 2022 and 2023. … The firm capacity to be delivered under the terms of the Contracts, and the resulting potential to defer or delay a portion of FPL's next generating unit, meets

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

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			the requirement of Rule 25-17.0832(3)(a), F.A.C. (which addresses the need for capacity by the purchasing utility and the state as a whole). Therefore, upon review, we find that approval of the proposed Contracts will enhance FPL's system reliability, encourage the use of renewable fuels in Florida, and promote fuel diversity for FPL's ratepayers."
	FPL, DEF, TECO	2012 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2012 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes."
130199 130200 130201 PSC-14-0696-FOF-EU	FPL, DEF, TECO	DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
	FPL, DEF, TECO	2013 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Based on its review, the Commission finds the 2013 TYSPs filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes. Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing."
140110 PSC-14-0557-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Citrus County plant. "As described by Witness Borsch, DEF employs two reliability criteria in its resource planning process: (1) a loss of load probability criterion, and (2) a reserve margin criterion. Witness Borsch stated that DEF's resource plans have been reviewed by this Commission each year since the early 1990s in the annual Ten-Year Site Plan review process. Witness Borsch asserted that the Company's need for the

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			proposed Citrus County Plant in the summer of 2018 is driven by the aforementioned reserve margin criterion. DEF's minimum reserve margin threshold is 20 percent and the Company calculates its reserve margin based on the relationship between peak load and total capacity available to serve that load. In addition to DEF's claimed need to satisfy its reserve margin criterion, Witness Borsch testified that the Citrus County Plant would provide reliability and stability to the Florida electric grid as determined by the Florida Reliability Coordinating Council, Inc. … There is no record evidence to indicate the recession has fundamentally altered DEF's expected forecast result for 2018 demand in a manner that casts doubt on the forecast. We find DEF's load forecast presented in this docket to be reasonable for the purposes of determining the need for DEF's proposed Citrus County Plant in 2018. Based on the evidence in the record, if DEF did not construct the proposed Citrus County Plant in 2018, the projected reserve margin could drop as low as 12.3 percent in 2018."
140111 PSC-14-0590-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Hines unit Chiller project. "Based on the evidence in the record, we recalculated DEF's originally filed reserve margin to ensure that the Company still has a reliability need in 2017. Table 2, below, shows that DEF's reserve margin in 2017 would fall to 19 percent absent any new generation. This represents a 94 MW need. Although, the need is relatively small, Witness Borsch testified that the addition of the Hines Project is cost-effective even when the capacity of the project was not needed to meet the Company's reserve margin criteria. We also note that no party in this docket disputed the need for the Hines Project. … Given a 20 percent reserve margin criterion, we find that the evidence in the record demonstrates a need for the Hines Project beginning in 2017. Based on our calculations, if DEF did not construct the proposed Hines Project in 2017, the projected reserve margin could fall below the Company's 20 percent criterion."
	FPL, DEF, TECO	2014 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the 2014 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production. Based on its review, the Commission finds the 2014 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing."
	FPL	2015 TYSP Review	"Based on its review, the Commission finds all 11 reporting utility's 2015 Ten-Year Site Plans to be suitable for planning purposes."
	FPL	Need Determination	Commission granted need determination for 2019 Okeechobee CC unit "We find that FPL demonstrates a need for additional generation, beginning in 2019, in order to maintain system reliability and integrity based on a reasonable load forecast and a 20% reserve margin criterion as discussed below". "We find that, based on a 20% reserve margin and FPL's load forecast, FPL demonstrates a need for new generation in order to maintain electric service reliability and integrity". "A utility's minimum planning reserves should not be addressed in the vacuum of an individual utility's need determination proceeding, but rather in a generic proceeding that allows input from other peninsular Florida utilities and the FRCC." "We agree that a need determination proceeding is not the appropriate forum to address what a utility's minimum reserves should be." "Rather, we find that the 20% reserve margin criterion utilized by FPL was established giving consideration to peninsular Florida and, thus, should not be changed absent similar consideration. Therefore, we find the 20% reserve margin remains appropriate for identifying the timing of resource needs, which is consistent with our prior decisions."
	FPL	2016 TYSP Review	"Based on its review, the Commission finds all 11 reporting utility's 2016 Ten-Year Site Plans to be suitable for planning purposes."
	FPL	2017 TYSP Review	"Based on its review, the Commission finds all 11 reporting utility's 2017 Ten-Year Site Plans to be suitable for planning purposes."

Comparison of FPL System NOX Emissions for Resource Plans 2 & 3

Year	(1) Plan 2 (Tons)	(2) Plan 3 (Tons)	(3) = (1) - (2) Plan 2 - Plan 3 (Tons)
2017	12,407	12,407	0
2018	11,216	11,071	145
2019	9,107	8,869	239
2020	7,548	7,293	255
2021	7,264	6,989	275
2022	6,407	6,575	(168)
2023	6,242	6,774	(532)
2024	6,367	6,904	(537)
2025	6,651	7,323	(672)
2026	6,548	7,232	(684)
2027	6,690	7,449	(759)
2028	5,871	6,429	(558)
2029	5,617	6,172	(556)
2030	5,841	6,361	(520)
2031	5,284	5,768	(484)
2032	4,808	5,345	(537)
2033	5,118	5,643	(525)
2034	5,034	5,505	(471)
2035	4,883	5,270	(387)
2036	5,425	5,839	(415)
2037	5,339	5,727	(388)
2038	5,458	5,759	(301)
2039	5,474	5,833	(359)
2040	5,461	5,845	(385)
2041	5,565	5,940	(375)
2042	5,651	5,925	(275)
2043	6,012	6,240	(229)
2044	6,072	6,317	(246)
2045	6,139	6,417	(278)
2046	6,141	6,365	(224)
2047	6,210	6,440	(231)
Totals =:	197,842	208,018	(10,176)

Comparison of the Major Drivers of Benefits in DSM Cost-Effectiveness: 2014 DSM Goals Docket Inputs and Forecasts versus 2017 Inputs and Forecasts

(Source: 2014 DSM Goals Filing/2014 TYSP and DBEC Docket Information)

(1)	(2)	(3)	(4) = (3) - (2)	(5) = (4) / (2)	(6)
	DSM Goals Avoided Unit (All costs in 2022$)	**DBEC Unit 7 (All Costs in 2022$)**	**Difference (DBEC Unit 7 - DSM Goals Avoided Unit)**	**% Decrease re $/kW or $/MWh**	**Comments**
Installed Cost (2022 $/kW without AFUDC)	$1,027	$675	(352)	-34%	DBEC Unit 7 has lower $/kW total installed cost
Fixed O&M plus Capital Replacement costs (2022 $/kW-yr, levelized)	$23.95	$19.73	(4.22)	-18%	DBEC Unit 7 has lower fixed O&M plus capital replacement costs
Variable O&M costs (2022 $/MWh)	$0.78	$0.23	(0.55)	-71%	DBEC Unit 7 has lower variable O&M costs
Average Net Operating Heat Rate (BTU/kWh)	6,334	6,119	(215)	-3.4%	DBEC Unit 7 has a lower heat rate
Natural Gas Costs (Weighted Avg. FGT Firm, $/mmBTU)					
for 2020:	6.31	3.59	(2.72)	-43%	Current forecasted gas prices are significantly lower
for 2025:	7.65	4.39	(3.26)	-43%	Current forecasted gas prices are significantly lower
for 2030:	9.19	5.20	(3.99)	-43%	Current forecasted gas prices are significantly lower
for 2035:	11.06	5.88	(5.18)	-47%	Current forecasted gas prices are significantly lower
for 2040:	13.32	6.43	(6.89)	-52%	Current forecasted gas prices are significantly lower
CO2 Compliance Costs ($/ton)					
for 2020:	0.00	0.00	0.00	0%	No cost so no difference
for 2025:	18.62	0.00	(18.62)	-100%	Current forecasted compliance costs are significantly lower
for 2030:	30.08	6.70	(23.38)	-78%	Current forecasted compliance costs are significantly lower
for 2035:	47.04	23.10	(23.94)	-51%	Current forecasted compliance costs are significantly lower
for 2040:	69.96	40.02	(29.94)	-43%	Current forecasted compliance costs are significantly lower

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080407-EG
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION FOR APPROVAL OF NUMERIC CONSERVATION GOALS

REBUTTAL TESTIMONY & EXHIBITS OF:

STEVEN R. SIM

Q. Is there anything else about this subject that you wish to discuss?

A. Yes. Witness Steinhurst's focus on identifying and including even hard-to-quantify capacity benefits seems a bit at odds with Witness Mosenthal's recommendation that energy goals are of paramount importance with demand goals being merely an afterthought. Because capacity benefits are driven by demand reduction, Witness Steinhurst is clearly pushing for demand-driven benefits, but Witness Mosenthal is focused almost exclusively on energy reductions. I interpret this as another lack of consistency between these two NRDC-SACE witnesses in regard to what they believe the primary focus of DSM goals should really be – demand or energy reductions.

V. NRDC-SACE's "Economic Analysis"

Q. Did any of the NRDC-SACE witnesses provide a meaningful, comprehensive economic analysis that showed what the results would be for any Florida utility system if it were to adopt their recommended approach to goals setting?

A. No.

Q. Did they provide any economic analysis at all?

A. No. The entire extent of their "economic analysis" was to state in various testimonies that (paraphrasing) it costs less on a cents/kWh basis to save a kWh through DSM than to generate a kWh with a new power plant. Witness Wilson's testimony includes an Exhibit JDW-3, page 9 of 15 that shows the *"levelized cost of new energy resources in cents per kWh"* to be in the 2 to 4 cents/kWh range for energy efficiency and in the 7.3 to 10 cents per kWh range for a combined cycle unit. (Other Supply options are addressed as well.) Witness Mosenthal quotes this same price range of 2 to 4 cents per kWh for DSM on page 34, lines 2 – 3 of his testimony. Witness Steinhurst's testimony states that *"the cost of saved energy for those leading DSM programs is on the order of $0.02 – 0.03/kWh"* on page 30, lines 1 – 2. Neither Witness Mosenthal nor Witness Steinhurst state whether the values they quote are levelized values or represent some other type of value.

Unfortunately, this is the full extent of NRDC-SACE's "economic analysis" that is provided to support their recommendation of how DSM goals should be set for Florida.

Q. **Did their testimonies at least provide the information used to develop these cents per kWh values so that one could determine key aspects of the calculation including, but not limited to: which DSM programs were examined, what costs were included in the calculations, what costs were excluded in the calculations, the vintage of assumptions, what years the calculation addressed, what year or years the costs were levelized to, and how the calculations were performed?**

A. No.

Q. Besides the fact that no explanation or detail is provided for these calculations, what is your reaction to NRDC-SACE's use of a cents/kWh approach for comparing resource options?

A. I was both surprised and disappointed in their "economic analysis." I was surprised because the testimonies of the NRDC-SACE witnesses repeatedly attempt to make the case that the RIM test; i.e., a cost-effectiveness test that measures the impacts to the utility system's cents/kWh electric rate of competing resource options, is not the appropriate test to use in judging DSM options that compete with Supply options. Nevertheless, all three of these NRDC-SACE witnesses have attempted to compare competing resource options on a cents/kWh basis and state that the results of this electric rate comparison should be used to justify the selection of DSM options.

Therefore, despite their protestations to the contrary, it is obvious that the NRDC-SACE witnesses really believe that a comparison of resource options that is based on an electric rate comparison is the correct way by which to conduct economic analyses of competing resource options. On that basic point the NRDC-SACE and I are in complete agreement.

However, I was also disappointed because NRDC-SACE's witnesses have selected an analytical approach that is fundamentally flawed for the analysis they are trying to use it for: an economic comparison of two very different resource options.

Q. Why is their analytical approach fundamentally flawed when used to compare two resource options that are as different as a DSM measure and a Supply option?

A. The problems in using this analytical approach for comparing two widely dissimilar resource options such as DSM and a Supply option have been previously discussed in prior Commission proceedings. However, if NRDC-SACE (and GDS) truly believe that this is a "best practice" analytical approach, it is probably worthwhile to discuss this issue again in depth.

Let's start by focusing on Witness Wilson's levelized cost values. (Although it is reasonable to assume that the cents/kWh values used by witnesses Mosenthal and Steinhurst are also levelized cost values, their failure to adequately describe what these values represent leaves one unsure.)

The analytical approach behind the levelized cost values presented by Witness Wilson is generally referred to as a "screening curve" analysis. In a screening curve analysis, one looks at a resource option, assumes that it operates at a given capacity factor or a range of capacity factors, and then calculates the present value costs of operating <u>only this individual resource option</u> over a number of years. These costs are then typically presented in terms of a levelized (or constant) \$/MWh, or the equivalent levelized cents/kWh, value over the years addressed in the analysis.

By using this analytical approach to compare two very dissimilar resource options - a DSM measure versus a Supply option (for example, a baseload generating unit such as a combined cycle or nuclear unit) - NRDC-SACE (and GDS) is making a classic error that I have seen beginning resource planners and inexperienced analysts make of trying to utilize a screening curve approach to analyze two resource options that impact the utility system in very different ways.

The usefulness of a screening curve analysis is actually very limited. It can be used in a meaningful way to compare the economics of two competing resource options that are identical or very comparable in at least the following four (4) key characteristics: (i) capacity (MW); (ii) annual capacity factors; (iii) the percentage of the option's capacity (MW) that can be considered as firm capacity at the utility's system peak hours; and (iv) the projected life of the option. If two resource options are identical or very comparable in at least these four key characteristics, then a screening curve analysis can be meaningful and one could "screen out" the less attractive of the two almost identical options. (This leads to the common terminology of this type of analysis as a "screening curve" analysis.)

However, a screening curve analytical approach that attempts to compare resource options that are not identical or even closely comparable in at least these four characteristics will produce incomplete results that are of little value. Indeed, the less comparable these characteristics are for the resource options being analyzed, the less meaningful are the results. Because a DSM measure and a combined cycle unit are about as different in terms of resource options as one can get, a screening curve approach attempting to analyze these types of resource options provides meaningless results.

The reason is because a typical screening curve analysis does not address the numerous economic impacts that these resource options will have on the utility system as a whole. Instead, a screening curve approach merely looks at the cost of operating the individual option itself. One can think of a screening curve analysis as examining the costs of a resource option if it were placed out in an open field by itself and operated without its operation having any impact on the utility system. The numerous impacts an individual resource option has on the utility system – for example, how it impacts the operation of all the other generating units on the system – is typically ignored in a screening curve approach.

However, the system impacts of any resource option are very large and can result in significant system cost savings that should be credited back to the resource option in order to have a complete picture. Any analytical approach, such as a screening curve approach, that ignores system cost impacts can only provide an incomplete, and therefore incorrect, result.

Q. Can you provide an example of a system cost impact that is not captured in a screening curve analysis for a single new resource option?

A. Yes. Let's assume that the resource option in question is a combined cycle unit. In a screening curve analysis, one assumes that this generating unit will operate at a particular capacity factor (or range of capacity factors). For purposes of this discussion, we'll assume the generating unit operates 90% of the hours in a year. Then, using the generating unit's capacity and heat rate, plus the projected cost of the fuel the generating unit would burn, the annual fuel cost of operating the generating unit for 90% of the hours in a year is calculated. This calculation is then repeated for each year addressed in the screening curve analysis.

In a screening curve analysis, the unit's annual fuel costs – which will be very large for a baseload generating unit – are added to all of the other costs (capital, O&M, etc.) of building and operating this individual generating unit. The present value total of these costs is then used to develop a levelized $/MWh or cents/kWh cost for this generating unit.

However, the screening curve analysis approach does not take into account the fact that this new baseload generating unit would not operate on a utility system at 90% of the hours in a year if it was not cheaper to operate this new unit than to operate other existing generating units on the system. In other words, for every hour the new baseload generating unit operates, the MWh it produces displace more expensive MWh that would have been produced by the utility's existing generating units. Whatever the annual fuel cost is of operating this new generating unit 90% of the hours in a year, the utility will save an even greater amount of system fuel costs saved by reducing the operation of one or more existing units during these hours.

For example, let's say that the new generating unit's annual fuel cost would be $100 million per year, but that the operation of this new unit will also result in a savings of $110 million in fuel costs from reduced operation of the system's more expensive existing units. A typical screening curve analysis will include the $100 million cost value for the individual unit, but ignore the $110 million in system fuel savings that will also occur.

For this reason a typical screening curve analysis approach utilizes an incomplete set of information and, therefore, is an incorrect way to thoroughly analyze resource options. A complete analytical approach would take into account the total system fuel cost impact of a net system fuel savings of $10 million (= $110 million in system fuel savings - $100 million in unit fuel cost) instead of only the fuel expense of the individual combined cycle unit. Consequently, a typical screening curve analysis will grossly overstate the actual net system fuel cost of the new generating unit.

In similar fashion, other system cost impacts, such as environmental compliance costs and variable O&M, are not accounted for in typical screening curve analyses because this approach does not take into account the fact that the new generating unit will reduce the operating hours of the utility's existing generating units. Nor does a screening curve approach account for the impact the resource option will have in regard to meeting the utility's future resource needs. Therefore, the screening curve approach utilizes incomplete information for a number of cost categories, thus providing incorrect results.

Q. The discussion above showed how a screening curve analytical approach utilizes incomplete information and leads to incomplete system cost results for a single new resource option. Is the screening curve approach become even more problematic when attempting to compare two or more different types of resource options?

A. Yes. This can be shown by a qualitative discussion that looks at several different types of resource options. Let's assume that a screening curve approach is used in an attempt to economically compare a few different resource options, three utility generating options and one DSM option:

- Combined cycle option A (1,000 MW)
- Combined cycle option B (1,000 MW)
- Combined cycle option C (500 MW)
- DSM option (100 MW)

Let's assume that the first comparison attempted is of two virtually identical combined cycle (CC) units, CC options A and B, in which the four key characteristics of the two CC units are identical. But let's assume that the capital cost of CC option A is lower by $1 million than the capital cost of CC option B.

In this comparison, even though a screening curve analysis will not provide an accurate system net cost value as per the above discussion, because the impacts to the operation of existing generating units on the system will be identical from two CC units that are the same in regard to capacity (1,000 MW), capacity factor (due to an assumption of identical heat rates and other factors that drive capacity factor), the amount of firm capacity (1,000 MW) each unit will provide, and the life of the two units, a screening curve analysis will give a meaningful comparison of the two options. (In other words, even though the results will not be accurate from a system cost perspective for either of the two options, the results will be "off" by the same amount and in the same direction.) As would be expected, the screening curve results will show that CC option A results in a slightly lower $/MWh value for CC option A compared to CC option B due to its $1 million lower capital costs.

As this example shows, a screening curve analytical approach can produce meaningful results in a case in which the four above-mentioned characteristics of resource options are identical or very comparable. However, as the ongoing discussion will show, once these factors for competing resource options are no longer comparable, a typical screening curve approach cannot produce meaningful results.

Q. Why would a screening curve approach break down if one attempted to compare otherwise identical generating units that differ only by their size such as CC option A (1,000 MW) and CC option C (500 MW)?

A. Now at least one of the four key characteristics of resource options that must be identical or very comparable in order for a screening curve approach to provide meaningful results differ significantly between CC option A and CC option C. This is the capacity of the two options: 1,000 MW for CC option A and 500 MW for option C. Even if one were to assume that all other assumptions for the two units were identical (capacity factor, percentage of capacity that is firm capacity, life of the units, heat rate, capital cost per kW, etc.), the significant difference in capacity offered by the two options would cause a screening curve approach to yield incomplete, and therefore incorrect, results.

The capacity difference between these options would result in at least two system impacts that would not be captured by a screening curve approach. The first of these is the impact of each of the two CC options on the utility's future resource needs. The 1,000 MW of CC option A will address the utility's future resource needs twice as much as will the 500 MW of CC option C. Therefore, CC option A will avoid/defer future resource additions to a greater extent that will CC option C. This will show up in a system cost analysis in the form of different system capital, fuel, O&M, environmental compliance, etc. costs beginning at some point in the future when the utility begins to have resource needs.

In addition, even prior to that point in the future when new resources are needed, the 500 MW greater capacity of CC option A will result in different system fuel cost, variable O&M, and environmental compliance cost impacts as the operation of the utility's existing generating units are reduced to a greater extent than with CC option C.

None of these system economic impacts that are driven by the difference in the capacity of two competing resource options are typically captured in a screening curve approach. The earlier discussion pointed out that a screening curve approach applied to even a single new resource option will omit a variety of significant system cost information that is necessary to develop a complete cost perspective of the one resource option. Now we see that an attempt to use a screening curve approach to compare the economics of two resource options that differ significantly in only their capacity will omit an even greater amount of important system cost information. Therefore, the use of a screening curve approach is definitely flawed when used to compare two new resource options that differ in just one of the four key characteristics listed above.

Q. The previous examples discussed only Supply options. Do similar problems exist if one were to attempt to compare DSM options to supply side options using a screening curve approach?

A. Yes. All of the problems inherent in using a screening curve approach that omits the system cost impacts discussed above are equally applicable whether Supply or DSM options are being addressed.

In this example, the system impacts of the lower amount of DSM (100 MW) on future resource needs would not be captured in a typical screening curve analysis. This would lead to the same type of incomplete and incorrect analysis discussed previously. Even if one were to adjust the 100 MW of demand reduction from DSM to account for the fact that 100 MW of DSM would be equivalent to 120 MW of supply side capacity (if the utility had a 20% reserve margin criterion), 120 MW of one option will be at a disadvantage compared to larger resource options in terms of avoiding/deferring future resource needs of the utility.

In addition, DSM options vary widely in terms of their actual contribution during system peak hours. Many DSM programs reliably reduce demand during the summer and winter peak hours such as load control, building envelope, heating/ventilation/air conditioning (HVAC) programs to name a few. However, other DSM programs may contribute little or no demand reduction at the summer peak hour, at the winter peak hour, or at either peak hour. A streetlight program would be an example of such a program.

Presentations of screening curve analyses of DSM options, such as in Witness Wilson's exhibit, typically lump a wide variety of DSM options together regardless of the capability of these DSM options to lower peak hour demand. This form of presentation further clouds one's understanding of what DSM options are actually being addressed and does not allow an observer to fully understand the breadth of the system impacts that are not being captured in a screening curve analysis.

Q. Please summarize why a comprehensive economic analysis that includes system cost impacts of resource options, such as the analytical process FPL utilized, is superior to the NRDC-SACE screening curve "economic analysis" approach?

A. There are a large number of cost impacts to consider if one is attempting to provide a complete analysis of competing resource options. Some of these cost impacts are driven solely from the operation of the resource option itself while other cost impacts are utility system impacts driven by integrating and operating a resource option with the utility's existing generating units.

A screening curve approach typically addresses only the costs of operating the individual unit itself. As discussed above, this approach omits all of the system cost impacts that are crucial to capturing the complete costs of a resource option.

In contrast, a system economic approach – such as that utilized by FPL in the analyses presented in this docket - not only captures all of the costs of operating the individual resource option, but also captures the system costs and cost savings of operating the entire FPL system with the resource option.

Q. Can you provide a quantitative example of how the cents per kWh results of a typical screening curve approach might change if one were to account for even one or two system impacts that are typically omitted by this analytical approach?

A. Yes. Staff Interrogatory Number 57 in this docket requested the results of a screening curve analysis of the 2019 combined cycle unit used in FPL's DSM screening analyses. FPL provided these results, along with a condensed version of the qualifiers discussed at length above that explain the significant limitations of using this levelized cost value when comparing a combined cycle unit to very dissimilar resource options.

The levelized cost value FPL provided in response to Staff's request is \$162/MWh assuming a 90% capacity factor with costs levelized in 2019\$. This value is equivalent to a levelized 16.2 cents/kWh in 2019\$. (Screening curve analyses are often presented in levelized \$/MWh values for either the in-service year of the unit or for the year in which the analysis was performed.) As previously mentioned, NRDC-SACE provides no information regarding what year $ their levelized values are in. Let's give them the benefit of the doubt and assume that they at least tried to put the values for the resource options (which would almost certainly have different in-service years) on a common year basis. This is most commonly done through levelizing costs to the year in which the analysis was done. Therefore, let's convert the $162/MWh value in 2019$ to an equivalent 2009$ value.

Exhibit SRS-14 provides the summary page of that analysis. The levelized value for this same unit at a 90% capacity factor now becomes $69/MWh in 2009$. This value is highlighted in the box on the left-hand side of the page. This exhibit shows that FPL accounted for all projected costs of building and operating this individual unit over the projected 25-year life of the unit. The calculation does not account for offsetting system cost impacts as is typical in screening curve analysis. Because NRDC-SACE presented their values in terms of cents/kWh, I'll do so as well. The $69/MWh value translates to 6.9 cents/kWh. (NRDC-SACE's value for a CC unit was in the 7.3 to 10.0 cents/kWh range.)

Exhibit SRS-15 now takes a more realistic, but still highly conservative assumption (in order to make the math easier to follow and to be consistent with the system fuel cost savings example discussed above). In Exhibit SRS–

15, the impacts of only two of the many system impacts have been included: system fuel savings and system environmental compliance cost savings.

The conservative assumption used is that both the system fuel cost savings and the system environmental compliance cost savings will be 10% of the combined cycle unit's costs in those categories. For example, the fuel cost value for this individual unit for the year 2019 in Exhibit SRS–14 is $865,447 (in $000). The new assumption used in developing Exhibit SRS-15 is that the system would actually realize a saving of 1.10 x $865,447 ($000) = $951,992 ($000) from reduced operation of the other units on the system.

Consequently, a net system fuel savings of $86,545 ($000) (= $951,992 - $865,447) would occur. This value shows up as a negative value, ($86,545) ($000), in Exhibit SRS–15 for the 2019 fuel cost value to denote this savings. A similar calculation is made for all years for the fuel costs and the environmental compliance costs.

Even with this conservative assumption for FPL's system, the screening curve's levelized cost value for the combined cycle unit at a 90% capacity factor has now dropped from $69/MWh or 6.9 cents/kWh to $12/MWh or 1.2 cents/kWh.

Therefore, even by making a simple adjustment to a screening curve analysis to account for only two of many system impacts of adding a combined cycle to a utility system such as FPL's, the levelized cost projection from the screening curve analysis is dramatically lowered from 6.9 cents/kWh to 1.2 cents/kWh. And, as discussed previously, there are a number of other system impacts that still not accounted for in this example.

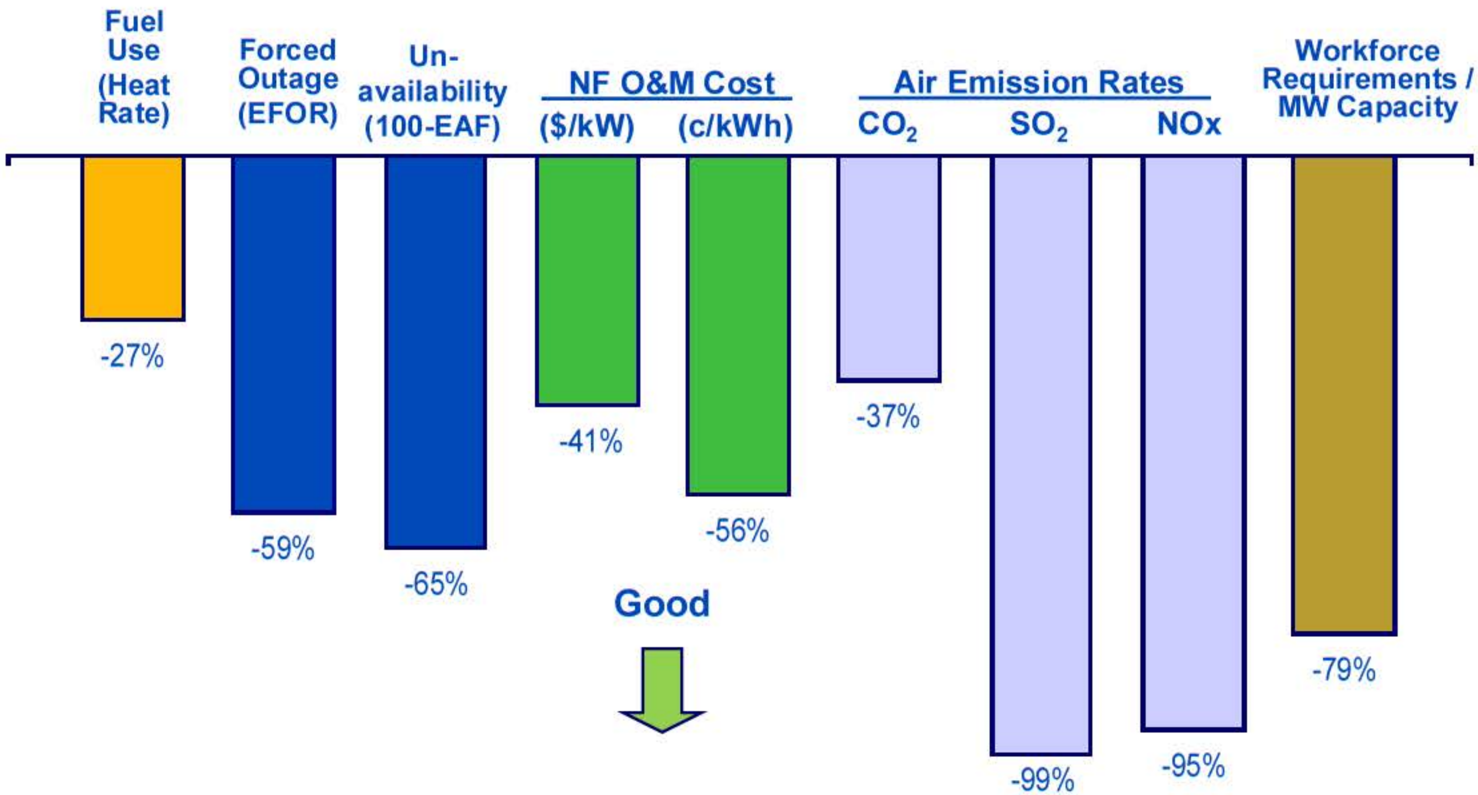
The moral of the story is that, by leaving out system cost impacts, typical screening curve analyses are based on very incomplete information and can provide very misleading results as demonstrated by this example. This points out how meaningless the cents per kWh values are that NRDC-SACE presented as its "economic analysis."

Q. In summary, how should one view any economic analysis based only on a screening curve analysis?

A. When a person attempts to justify a resource option selection solely with a screening curve analysis, the individual attempting to use such an analysis as justification either does not understand how utility systems work, or knows better but is trying to sneak out a decision that would be based on very incomplete information.

The Commission, and any other interested party, should view a screening curve analysis as an approach that utilizes only an incomplete subset of information, and which, therefore, provides incorrect analysis results.

FPL Fossil Fuel Generation Fleet Performance Improvements
(1990-2016)



Year	BTU/kWh	EFOR %	100-EAF %	$/kW	c/kWh	Lbs/MWh	Lbs/MWh	Lbs/MWh	Empl/MW
1990	10,214	2.77	100-81.7=18.7	18.5	0.64	1,464	6.51	5.24	0.21
2016	7,428	1.14	100-93.4=6.6	11.0	0.28	929	0.06	0.26	0.04
Results >>	More Efficient	More Reliable	More Available	Lower Cost	Lower Cost	Cleaner	Cleaner	Cleaner	More Productive

FPL's fossil fleet improvements in efficiency, reliability, cost, emissions and productivity are integral to cost-effectively generating electricity for customers

FPL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING THE DANIA BEACH CLEAN ENERGY CENTER UNIT 7

REBUTTAL TESTIMONY OF HECTOR J. SANCHEZ

DOCKET NO. 20170225-EI

DECEMBER 22, 2017

Q. Please state your name and business address.

A. My name is Hector J. Sanchez. My business address is Florida Power & Light Company, 4200 West Flagler Street, Miami, FL 33134.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Director of System Operations.

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

A. I am responsible for the real time operation of FPL's Bulk Electric System ("BES" or "FPL System"). I also serve as the Florida Reliability Coordinating Council ("FRCC") Reliability Coordinator, in an agent capacity for the FRCC. The FRCC is one of the eight regions in the United States (U.S.) under the jurisdiction of the North American Electric Reliability Corporation ("NERC") for reliable operations of the BES.

Q. Please discuss the real time operation of the FPL system and the role of the FRCC Reliability Coordinator.

A. The real time operation of FPL's BES requires coordinating, directing and controlling in a reliable and efficient manner the operations, planning, and real time dispatching of FPL's generation, transmission, and substation facilities from FPL's System Control Center to serve over 4.9 million FPL retail customer accounts, as well as its wholesale customers and its transmission service obligations. The FPL system, which is one of the largest in the U.S., is comprised of approximately 600 substations and almost 7,000 miles of transmission lines ranging in voltage level from 69,000 to 500,000 volts and over 26,000 MW of generation resources.

As the FRCC Reliability Coordinator, I coordinate and ensure the reliable real time operation of over fifty utilities in the FRCC region as well as the coordinated operations with other regions, including the Southeast Electric Reliability Council to which the FRCC connects to. In essence, I keep track of how every utility in the FRCC will be and is operating its BES and making sure that the reliability of their system and the FRCC is not compromised, and in the event that I determine it is, I have the authority to modify the operations as I deem necessary.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Miami in December, 1985. In 1990, I completed the Southeastern Electric Exchange's Course in Modern Power Systems Analysis held at Auburn University. In 1991, I received a Master of Business Administration degree from Florida International University. Additionally, I have completed various other power system courses offered by Power Technology Incorporated ("PTI"), courses offered internally at FPL, and business and management courses at Columbia University.

Since joining FPL in 1986, I have held positions of increasing responsibility. My first positions at FPL were as an Applications Engineer in the Power Systems Control group and as an Engineer in the Protection and Control department. In 1989, I joined the System Operations group in the area of operations planning where I was responsible for performing technical analyses associated with short-term planning and operation of the FPL system. In 1994, I became a Transmission Business Manager where I was responsible for issues associated with the provision of transmission service. Subsequent to that assignment, in March 2000, I held the position responsible for the planning of the bulk transmission system and interconnections. In January of 2006, I became responsible for the operation and dispatch on a real time basis of the FPL system. Later that same year, I became the Director of Transmission Planning and Services in which I was responsible for matters relating to the provision of transmission services on the FPL system and for planning the expansion of the FPL transmission system to meet the requirements of FPL's retail customers, wholesale customers, and its transmission service obligations. In 2009, I assumed my current position as Director of System Operations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut Sierra Club's witness Dr. Hausman's claim on Page 22 of his direct testimony that "…there is no apparent reason why four years is any kind of 'magic number,'…." for the time period from retirement and demolition of Lauderdale Units 4 and 5 to the commercial operation date of the Dania Beach Clean Energy Center ("DBEC Unit 7") and to explain how he fails with this contention to take into account important operational considerations for the FPL system. My testimony provides an operations and reliability perspective backed by 31 years of experience for a critical dense urban region of Florida. Specifically, Dr. Hausman does not consider a "real life" operations perspective on why it is critical that the DBEC Unit 7 be constructed and commissioned within the demolition and construction period of four years following the retirement of Lauderdale Units 4 and 5 beginning by late-2018. In regards to the resource planning analysis, and in particular to the delay scenario proposed by Dr. Hausman, I provided FPL Witness Sim specific guidance regarding the importance of constructing the DBEC Unit 7 with the present proposed schedule. Constructing and commissioning the DBEC Unit 7 within this four-year schedule minimizes the operational risk to the FPL System in providing reliable service to customers in Miami-Dade and Broward Counties (the "Southeastern Florida region"), one of the largest metropolitan areas in the U.S.

Q. Please summarize your testimony.

A. My testimony provides a discussion of the operational realities and risks that are faced in the Southeastern Florida region. These operational realities require a robust area reliability margin that will be greatly assisted by placing in- service the DBEC Unit 7 by the soonest practicable date, following the CSQ facilities going in-service and the retirement of the existing Lauderdale

Units 4 and 5, such that the risk of being unable to provide reliable service to FPL's customers is minimized.

Q. Please describe the Southeastern Florida region that is a focus of this docket and how FPL's customers in this area are served.

A. The Southeastern Florida region is comprised of Miami-Dade and Broward Counties. It is essentially an "electrical peninsula" where over 40% of FPL's total 4.9 million customer accounts are served from a combination of generation resources within this region and by finite transfer capability through transmission and substation facilities from outside this region. The amount of generation in the Southeastern Florida region is also finite, totaling approximately 5,280 MW, after the Lauderdale Units 4 and 5 are retired in late 2018[1]. The capability to import power into the area via transmission and substation facilities is also finite; this capability is forecasted to be 7,200 MW when the CSQ transmission facilities are placed in-service and the Lauderdale Units are retired. As such, the load serving capability, presuming all generation resources, transmission, and substation facilities are in-service and performing as designed, is approximately 12,480 MW.

FPL's service obligations in the Southeastern Florida region include not only FPL's retail load, but also Transmission Service obligations (City of Homestead, Florida Keys Electric Cooperative, and the City of Key West)

[1] 5,280 MW is the sum of the output of the following generation units: Turkey Point (TP) 3 and 4 totaling 1,672 MW; TP 5 totaling 1,147 MW; Lauderdale 6 CTs totaling 1,155 MW; Port Everglades (PE) totaling 1,237 MW; and GTs totaling 69 MW.

which are forecasted in year 2022 to be approximately 10,789 MW[2]. But in reality, high loads or loads that exceed 90% of the annual forecasted summer peak, do not occur on just one day for one hour in August as is typically seen in a planning reserve margin calculations. For the past three summers from May 15th through September 15th (124 days which is considered the high load season for real time operations), FPL's load exceeded 90% of the annual summer forecasted peak on 37 to 56 days of the total days within this time frame. Furthermore, FPL's loads exceeded 90% of the peak load forecast on each of those days for an average of almost six hours from approximately 1 PM to 7 PM. As such, FPL is exposed to prolonged periods of high loads, where operational risk is much higher, for approximately one third of the year, and during those days when the load exceeded 90% of the annual summer forecasted peak for one quarter of the day, as evidenced by the up to 354 hours (product of 56 days and 6 hours per day) per year in each of the years from 2015 through 2017.

Q. What do you consider when managing the real time operations of the load serving capability and service obligations that you discuss?

A. I take into account the forecasted load, available transmission, substation, and generation resources. Additionally, I consider operational situations that may be applicable based on my years of experience operating the system and

---

[2] FPL uses for Transmission Planning and Operations purposes a "P80" load forecast instead of the "P50" that is used by Resource Planning in assessments. The P80 for the Southeastern Florida region is approximately 200 MW higher than the P50. The rationale for using the P80 is to account for non-coincidence of loads (*e.g.*, hotter temperatures in the Southeastern Florida region as compared to the rest of the state) and the need to have facilities in place that can meet such higher load. Note that a P80 still provides a 20% risk that the loads will be even higher.

mitigation measures. To help clarify my thinking, as part of this process with respect to Southeastern Florida region, I make use of what I term an "area" reliability margin calculation, which combines aspects of a reserve margin calculation and load flow analysis. For example, based on the projected load serving capability and service obligations for 2022, without DBEC Unit 7, FPL will have an area reliability margin at the forecasted peak load of approximately 1,691 MW for the Southeastern Florida region. The area reliability margin calculation, as it is used in the context for the specifics associated with the Southeastern Florida region, is different from a planning reserve margin calculation or a load flow analysis. Maintaining a robust area reliability margin for this area is important since it provides the critical support for the combination of unexpected situations that are common in the operations timeframe and more extreme situations such as hurricanes and wild fires.

Q. Please discuss potential events occurring in isolation or combination that can occur during the operations time frame.

A. On any given day, and sometimes for multiple days, during the high load season (May 15^{th} to September 15^{th}), generation resources such as Turkey Point (TP) Units 3, 4, or 5, or Port Everglades (PE) Unit 5 (or a combination thereof) may be unavailable. In accordance with NERC Reliability Standards, FPL must be prepared to sustain the sudden loss of any generation resource or transmission or substation facility at any time, while continuing to serve load reliably with all facilities within applicable ratings and voltages within limits.

Moreover, within 30 minutes after the loss of a generation resource or transmission or substation facility, FPL must replace this amount of generation and posture the system for the next contingency, such that if it were to occur, customers would continue to be served reliably. Additionally, there are strict voltage limits at the Turkey Point Nuclear Switchyard that are Nuclear Regulatory Commission requirements that must be adhered to on a pre-contingency basis. The bottom line is that as the operator of one of the largest electric systems in the U.S., comprised of one of the largest metropolitan areas in the U.S., FPL must have the resources needed to be able to reliably serve FPL's customers. This includes serving customers reliably with the potential for multiple resources - generation, transmission, and substation facilities - being unavailable on an unplanned and prolonged basis, while always being ready to have any other generation resource or transmission or substation facility trip out of service and continue to serve customers reliably.

For example, in 2022 when the area reliability margin for the Southeastern Florida region is projected to be 1,691 MW with all generation resources (without DBEC Unit 7) and import capability available, if PE5 (with a generation capacity of 1,237 MW) was to experience an unplanned outage during peak load summer conditions, the real time area reliability margin for this area would be 454 MW. A margin of 454 MW for the Southeastern Florida region would entail operating the FPL system without sufficient load serving capability to absorb the contingency of TP3, TP4, and/or TP5 also failing, and potentially, depending on the specific system conditions, possibly certain 500,000 volts equipment, also becoming unavailable. Multiple variations of the scenario described above are possible, which is indicative of the need for a more robust area reliability margin for the Southeastern Florida region, which will be greatly assisted by DBEC Unit 7.

Q. How will the area reliability margin change if the DBEC Unit 7 is not placed in service as you move forward in time?

A. By 2025, the area reliability margin for the Southeastern Florida region will decrease to 1,282 MW as the load continues to increase. This amount of area reliability margin is barely enough to cover the loss of PE5, let alone, any multiple unit outages. Regardless of which of the units in the Southeastern Florida region are unavailable, any multiple unit outages would result in FPL being unable to supply the entire load required by customers. This does not even account for the potential unavailability of transmission and/or substation facilities. This 2025 scenario is not a good situation to be in operationally because the risk of shedding firm load (*i.e.*, turning lights off) greatly increases in a scenario where more than one event occurs due to the reduced area reliability margin. I do not see where Dr. Hausman appreciates or recognizes this risk.

Q. Is it possible to have multiple units experience an unplanned outage at the same time?

A. Yes, absolutely. Not only is it possible, but unfortunately it sometimes occurs at the most inopportune time. For example, during the cold weather condition in the early morning hours in January, 2010, during which FPL's peak load was more than 6,000 MW higher than forecasted, FPL experienced 1,980 MW of unplanned generation outages. Additionally, just two hours after experiencing that winter peak, a TP nuclear unit at full output of approximately 750 MW experienced a sudden and unplanned outage that, if it were to have occurred just 2-3 hours prior, FPL would have likely been shedding firm customer load.

Q. Please provide more details on the more extreme situations that you previously mentioned?

A. Extreme and unexpected situations such as wild fires and hurricanes can pose a significant risk to serving customers in the Southeastern Florida region. Such occurrences cannot be addressed with traditional planning reserve margin calculations. On multiple occasions during my tenure leading System Operations, wild fires have occurred in the vicinity of the corridors that contain multiple transmission lines that bring power into this region. During these situations, FPL must posture its system for the loss of one or more of these multiple transmission facilities while continuing to serve its customers. This includes operating at full output all available generation resources in the Southeastern Florida region, such that if multiple transmission facilities trip due to the wild fire resulting in reduced load serving capability, FPL would reduce the chances of shedding firm customer load.

In fact, and as evidence of the criticality of this scenario, FPL's 2017 Annual Capacity Dry Run held last month simulated a fire in one of the corridors containing transmission lines that import power into the Southeastern Florida region. In this particular scenario, because the time frame simulated was during a high load period, the projected area reliability margin was insufficient, and FPL would have needed to shed tens of thousands of firm load customers for multiple hours to avoid a cascading instability situation or blackout in the region. I note that this result was projected even with the full 884 MW capacity of Lauderdale Units 4 and 5 in-service. Undoubtedly, the DBEC Unit 7 being brought in-service as soon as possible after the retirement of Lauderdale 4 and 5 would mitigate much of the need to perform firm load shedding in a future similar scenario and demonstrates that, all else being equal, it is better to have generation resources in the region where transmission import capability is heavily relied upon.

Hurricanes pose a similar threat to Southeastern Florida. For example, during Hurricane Matthew last year, FPL prepared for a scenario in which that storm would have impacted the area of Palm Beach County and northward. This scenario would have left the Southeastern Florida region unscathed, but could have resulted in damage to generation resources and transmission facilities that contribute to the import of power into the Southeastern Florida region. In such a scenario, having additional generation resources in Southeastern Florida would obviously be advantageous in mitigating the risk.

Q. Is there any other point you would like to discuss regarding the area reliability margin?

A. Yes. When DBEC Unit 7 comes on line, it improves the area reliability margin for the Southeastern Florida region in two ways. Specifically, DBEC Unit 7 provides an additional 1,563 MW of area reliability margin comprised of 1,163 MW from the DBEC Unit 7 and approximately 400 MW more import transfer capability. The 400 MW of import transfer capability results from where and how the DBEC is connected to the FPL system and the resulting impacts on power flows on the transmission and substation system.[3] This increase in 2022, when the DBEC Unit 7 is placed in service, results in an area reliability margin for the Southeastern Florida region of 3,254 MW. This is the magnitude of area reliability margin that I consider sufficient for one of the major metropolitan areas of the U.S.

Q. Why are you concerned with Dr. Hausman's delay discussion on pp. 21-23 of his testimony in this proceeding?

A. Dr. Hausman implies that delaying the in-service date of the DBEC Unit 7 by several years should be considered while keeping the 2018 retirement date as planned for Lauderdale Units 4 and 5. I disagree. Delaying the in-service

---

[3] The CSQ line will provide an increase in import capability into the Southeastern Florida region of approximately 1,200 MW assuming that either Lauderdale 4 & 5 or DBEC Unit 7 is in operation. With the retirement of the Lauderdale units, and no DBEC Unit 7, this increase in import capability is only about 800 MW. The import capability returns to 1,200 MW as soon as DBEC Unit 7 goes into service.

date of DBEC Unit 7 after retiring Lauderdale Units 4 and 5 would increase operational and reliability risk to Southeast Florida at a time when we are focused on reducing risk to the region. As I discuss above, it is imperative that a robust area reliability margin be maintained for the Southeastern Florida region. This region is one of the major metropolitan centers of the U.S. which continues to grow at a relatively fast pace as seen by the sky line from downtown Miami northward. Additionally, the delaying of the DBEC Unit 7 to after 2022 and, after retiring the 884 MW from the existing Lauderdale Units in 2018, not only reduces the area reliability margin by the 884 MW that would be unavailable from the existing Lauderdale generation resources, and delays the additional 400 MW of transmission import capability that will occur once DBEC Unit 7 goes in-service, but does so in the face of projected load growth during the years 2023 to 2025 in the Southeastern Florida region. This projected load growth further reduces the area reliability margin by 409 MW. As such, the sooner the DBEC Unit 7 project is placed in service the less the risk there is to the Southeastern Florida region, especially in the latter years. Combinations of the high loads during prolonged periods of the year, unplanned generation, transmission, and/or substation outages, exacerbated by any delay with the in service date of the DBEC Unit 7, will result in increased operational challenges and risks to serving customers in the Southeastern Florida region. Constructing DBEC Unit 7 as soon as practicable decreases this risk to the Southeastern Florida region.

Q. Dr. Hausman suggests that additional demand response ("DR") resources, at least in part, could be substituted for DBEC Unit 7. Please discuss how you consider FPL's residential and commercial/industrial load management capabilities in Southeastern Florida region in your analysis of the available area reliability margin.

A. In the event that the area reliability margin for Southeastern Florida region is exhausted, FPL would use its DR capabilities to reduce the load in this area. It is important to note that DR is not utilized for economic purposes, but solely for reliability as a resource when all other generation resources and transmission imports have been exhausted. However, using DR for reliability reasons is different than using operating generation for reliability reasons for at least two reasons. First, the seriousness of using DR for reliability is evidenced by the fact that NERC Reliability Standard EOP-002 requires that in the event that FPL utilizes DR in such a context, it must declare itself to the FRCC Reliability Coordinator an Energy Deficient Entity, and in turn, the FRCC Reliability Coordinator would declare an Energy Emergency Alert Level 2, the second highest of three levels. Such declarations must not be taken lightly since they are indicative of serious operational reliability issues. It is clearly within the realm of possibilities that repeated use of such declarations would not be viewed favorably.

Second, there is the issue of how long FPL's system operators may need relief from extreme loads and/or problems with generation, transmission, and substation facilities. In the January 2010 situation previously discussed, FPL was operating all available generation, including its peaking units, around the clock for approximately 24 hours. DBEC Unit 7 will be capable of operating around the clock in such a circumstance. Conversely, as FPL witness Sim has discussed with me previously, there is a risk of losing DR capability after DR is operated repeatedly, and for multiple hours in each instance, due to participating DR customers dropping out of the programs as a result of experiencing the effects of their load being controlled repeatedly and for prolonged periods of time.

Q. Does the January 2010 situation offer other insight into Dr. Hausman's preference for solar and storage instead of DBEC Unit 7?

A. Yes. Of the resource options discussed in this docket, DBEC Unit 7 is uniquely capable of: (i) providing capacity and energy at FPL's winter peak hour of 6 AM to 7 AM, and (ii) operating continuously around the clock for 24 hours.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE
Docket No. 20170225-EI

I HEREBY CERTIFY that a true and correct copy of FPL's Rebuttal Testimony and exhibits of Dr. Steven R. Sim and Hector J. Sanchez has been furnished by electronic mail on this 22nd day of December, 2017 to the following:

Charles Murphy, Esq.
Stephanie Cuello, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
cmurphy@psc.state.fl.us
scuello@psc.state.fl.us

Julie Kaplan, Esq.
Diana Csank, Esq.
Michael Lenoff
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
Julie.kaplan@sierraclub.org
Diana.csank@sierraclub.org
Michael.lenoff@sierraclub.org

Patricia Christensen, Esq.
Office of Public Counsel
The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399
christensen.patty@leg.state.fl.us

Michael Marcil, Esq.
Gunster
450 E. Las Olas Blvd.
Fort Lauderdale, FL 33301
MMarcil@gunster.com

By: *s/ William P. Cox*
William P. Cox
Florida Bar No. 0093531