BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	DOCKET NO. 140110-EI Submitted for Filing July 15, 2014

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S
NOTICE OF FILING

Calpine Construction Finance Company, L.P. ("Calpine") hereby gives notice of filing the Direct Testimony of John L. Simpson, P.E. with Exhibits JS-1 through JS-2 in support of Calpine's positions regarding Duke Energy Florida, Inc.'s Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

Respectfully submitted this 15th day of July, 2014.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was furnished to the following, by electronic delivery, on this 15th day of July, 2014.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination Of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	**DOCKET NO. 140110-EI Submitted for filing: July 14, 2014**

DIRECT TESTIMONY

OF

JOHN L. SIMPSON, P.E.

ON BEHALF OF

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

ON BEHALF OF CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

FLORIDA PUBLIC SERVICE COMMISSION DOCKET NO. 140110-EI

DIRECT TESTIMONY OF JOHN L. SIMPSON, P.E.

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, employer, and business address.

A. My name is John Simpson and I am self-employed as a Transmission Engineering Consultant. My business address is 40318 Colfax Road, Magnolia, Texas 77354.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Calpine Construction Finance Company, L.P., a subsidiary of Calpine Corporation, (collectively "Calpine") in support of its intervention in this docket, which addresses Duke Energy Florida's ("DEF") Petition for Determination of Need for Citrus County Combined Cycle Power Plant. Calpine owns and operates the Osprey Energy Center ("Osprey" or the "Osprey Facility"), which is located in Auburndale, Florida.

Q. Please summarize your educational background and your employment experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Colorado in 1972. I began my career with the Public Service Company of Colorado where I held various engineering and engineering supervisory positions of increasing importance in electric utility generation and substation engineering. I then joined Florida Power Corporation ("FPC") in 1985 where I held various engineering management positions of increasing responsibility, serving for over six years as the Manager of Transmission Design where I was responsible for the overall project activities for the engineering, design, permitting, right-of-way acquisition, material procurement, and construction specifications for new transmission lines and modifications to existing transmission lines on the FPC system. I then served for over four years as the Director of System Planning where I was responsible for the planning of all transmission, substation, and major distribution facility additions on the FPC System. In that role, I was also responsible for administration of FPC's open access transmission tariff. In November 1999, I joined Reliant Energy where I served as the Director of Transmission Analysis. In this role, I was responsible for the transmission analysis activities required to support the trading, power origination, and generation development functions of Reliant Energy and its successor companies, RRI Energy and GenOn Energy, in the development, operation, and management of their merchant generation fleet throughout the United States. In April 2011, I began working as an independent transmission consultant for various merchant electric generators, including Calpine. In this role I provide transmission expertise related to generator interconnection and transmission access issues. I currently represent Calpine on the Florida Reliability Coordinating Council ("FRCC") Planning Committee, Operating Committee, and Regional Entity Committee and Compliance Forum.

I am a Registered Professional Engineer in the states of Colorado and Florida.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit JS-1	Resume' of John L. Simpson, P.E.
Exhibit JS-2	Excerpts from FPL Ten Year Site Plan - Turkey Point Synchronous Condenser Operation

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of the transmission system impacts and issues related to the opportunities for Calpine's Osprey Facility to deliver energy and capacity to the DEF Balancing Authority Area ("BAA") in the 2016 to 2019 and beyond time period.

Q. Please summarize your testimony.

A. Calpine's Osprey Facility is well positioned to deliver energy and capacity to the DEF BAA as a replacement or substitute for the Suwannee simple cycle peaking units ("Suwannee CTs" or "Suwannee Peakers") that DEF proposes in this proceeding to add in 2016 and the Hines Chiller upgrades ("Hines Chillers") that DEF proposes to add in 2017. In addition, Osprey provides a unique opportunity to complete a cost effective direct connection to the DEF transmission system by January 1, 2020, and possibly as early as the summer of 2017, to support a purchase option offered by Calpine. The direct connection to the DEF transmission system will not only fully integrate the Osprey generation into the DEF system, but will also provide ancillary transmission system benefits by creating a southern tie between the two largest load centers on the DEF system, the Florida Suncoast area (Pinellas, Pasco and Hernando Counties) and the Central Florida area (Orange, Osceola, and Seminole Counties), thus enhancing load and generation deliverability between these two areas.

Q. What is your understanding of the Osprey Facility and the proposals by which Osprey's capacity and energy would be delivered into the DEF balancing authority area?

A. I understand that Osprey is a nominal 599 MW, 2-on-1 natural gas fired combined-cycle facility located in Auburndale, Florida, that began commercial operation in 2004. Osprey can provide 515 MW of electric capacity.

I further understand that Calpine has offered to provide 515 MW of capacity and energy to DEF from 2015 through 2019 pursuant to the proposed terms of a power purchase agreement ("PPA"), and that, as part of its proposals, Calpine has offered to sell Duke the Osprey Facility outright at the end of the PPA term, i.e., on January 1, 2020. I understand that Calpine participated in a 2012 Request for Proposals ("RFP") conducted by Progress Energy Florida, which is now DEF, in which DEF sought proposals to meet its needs before 2018, and further that Calpine was selected for negotiations toward a PPA, although no PPA was ever executed.

III. TRANSMISSION ANALYSIS OF OSPREY DELIVERING TO DEF BAA

Q. Please describe Osprey's use of the transmission system.

A. The Osprey Facility was placed in commercial operation in 2004. It is interconnected to the Tampa Electric Company ("TEC") transmission system at the Recker 230 kV substation. ("TEC" is the common abbreviation for Tampa Electric Company in the FRCC and Florida transmission documents.) Since its construction, the Osprey Facility has delivered energy and capacity to DEF, TEC, and Seminole Electric Cooperative ("SEC" or "Seminole"). Calpine Energy Services, an affiliate of Calpine, has purchased Firm Point to Point ("PTP") transmission service from TEC for deliveries from the Osprey Facility to both the DEF and Florida Power & Light ("FPL") BAAs. From 2009 to 2014, most of the Osprey Facility's capacity and energy were sold to Seminole pursuant to a long-term PPA and, during this period, the Osprey Facility was designated as a Network Resource to serve SEC

Network Load in both the DEF and FPL BAAs. To deliver this Network Resource, Calpine purchased and utilized Long Term Firm PTP Transmission Service to deliver up to 249 MW of energy and capacity to the DEF BAA and up to 277 MW of energy and capacity to the FPL BAA. Upon the expiration of the Seminole contract, Calpine rolled over or extended the 249 MW of Firm PTP Transmission Service to the DEF BAA and allowed the 277 MW of Firm PTP Transmission Service to the FPL BAA to expire.

Q. Does Osprey still hold any transmission service rights on the TEC System?

A. Yes, Calpine Energy Services still owns the rights to deliver 249 MW of energy and capacity from Osprey to the DEF BAA through TEC using Firm PTP Transmission Service. These transmission service rights have rollover rights and may be extended in 5-year (or longer) increments for as long as Calpine continues to renew its transmission service agreement with TEC.

Q. Are there any pending developments in DEF's power supply system that are likely to impact the FRCC transmission system?

A. Yes. DEF recently retired its Crystal River 3 nuclear unit, and further plans to retire its Crystal River 1 and 2 coal units in the summer of 2018.

Q. Do the retirements of Crystal River Units 1, 2, and 3 create any problems or issues on the FRCC Transmission System?

A. Yes. The FRCC completed a study of the impacts of the retirement of Crystal River Units 1 and 2, with Crystal River Unit 3 already retired. This study, titled FRCC's Evaluation of Transmission Impact of the EPA's Mercury and Air Toxics Standard ("MATS") (Transmission Impact Study for Shutdown of Crystal River Units 1 & 2, with retirement of Crystal River Unit 3), is commonly called the "MATS Study" and has been provided as Exhibit ES-1 to the Direct Testimony of Ed Scott in this docket. The MATS Study showed that significant transmission issues would be created by the loss of such a large quantity of generation at the Crystal River site that then had to be replaced by dispatching other DEF resources within FRCC. Many of these transmission issues did not have a solution, or a solution could not be implemented within the time frame required if Crystal River Units 1 and 2 were shut down in April 2015 as required by the MATS regulation. For this reason, DEF was granted an extension for compliance with the MATS regulation until April 2016. DEF has subsequently developed a plan to allow Crystal River Units 1 and 2 to continue operation in compliance with the MATS regulation until summer of 2018, thereby providing additional time to replace this capacity or implement transmission solutions to the problems caused by their retirement. The plan developed by DEF would actually allow Crystal River Units 1 and 2 to operate through 2020 should DEF encounter delays or find it advantageous to delay replacing that capacity or implementing transmission solutions.

Q. Have you evaluated Osprey's ability to deliver to DEF as a resource to replace the planned additions at Suwannee and Hines?

A. Yes. As I mentioned previously, the retirements of Crystal River Units 1, 2, and 3 create significant issues on the FRCC transmission grid. However, if Crystal River Units 1 and 2 continue to operate through 2016 and 2017, as now planned by DEF, the deliverability of Osprey is much improved. I stated earlier that Calpine currently holds the rights to 249 MW of Firm PTP Transmission from Osprey to DEF. This service can be provided with no required upgrades on the TEC system. Calpine's current offer to DEF for energy and capacity from Osprey is for 515 MW with the 249 MW of Firm PTP Transmission Service included. This guarantees the delivery of 249 MW of energy and capacity from Osprey to DEF. Additional transmission service will need to be purchased from TEC for the delivery of additional energy and capacity from Osprey.

Q. What were the results of your evaluation of Osprey's ability to replace the planned additions at Suwannee and Hines?

A. With the support of Calpine's Transmission Department, I modeled the ability of Osprey to replace the addition of the Suwannee CTs (334 MW) in 2016 and the installation of the Hines Chillers (220 MW) in 2017. During the summer of 2016, with Osprey delivering 334 MW to the DEF BAA to replace the capacity of the new CTs at Suwannee, minor 69 kV issues were found under double contingency outages on the TEC system. From previous studies and solutions proposed by TEC, I believe all of these issues can be resolved through operating procedures by TEC. One 115 kV overload was found on the DEF system (on the Baker Tap to Miccosukee Tap line), also under a double contingency line outage. However, this overload already has an operating procedure that DEF currently uses to alleviate the overload under this contingency.

During the summer of 2017, with Osprey delivering 515 MW to the DEF BAA to replace both the new Suwannee CTs and the Hines Chillers, a few additional constraints were identified on the TEC system along with the overload of the Griffin to Morgan Road 115 kV line on the DEF system. Again, the issues on the TEC system should be resolved through operating procedures and/or redispatch of TEC resources. If minor construction to resolve 69 kV overloads is required, this can be completed in time to allow the transmission service to proceed and the cost of those upgrades would be rolled in to the transmission rate charged by TEC for the transmission service. The Griffin to Morgan Road overload on the DEF system would occur under a double line outage on the DEF system. DEF also has an existing operating solution to mitigate this overload that can be utilized for the summer of 2017 and beyond. If DEF exercises the purchase option offered by Calpine, a different long term solution can be put in place to mitigate all overloads caused by Osprey delivering to DEF.

Q. Please describe or give some examples of what you mean by "operating solutions" or "redispatch solutions."

A. Often a transmission overload does not warrant the construction of new facilities to eliminate its occurrence. This can be due to a number of reasons. For example, the overload can be very minor, or the probability of the causing events may be very low, such as a double contingency, or the cost of the new construction can be so high that it would not make economic sense to have customers pay for new construction to alleviate an overload that only occurs on rare occasions. In these instances, if the overload occurs, the utility must still meet the required NERC reliability standard requirements, so an "operating solution" is sought that will eliminate the overload and allow all facilities to return to their planned operating limits. The operating solution generally involves switching (i.e., opening and closing electrical breakers or switches on) the transmission system to reconfigure the system and redistribute transmission flows to eliminate the overload condition. The operating solution can also involve the redispatch of generation, that is, raising some generation output and lowering other generation. This is called a "redispatch solution" and it also changes the flow distribution on the transmission system. Generally an operating solution will include the most economic combination of switching and redispatch required to eliminate the overload condition.

Q. Do other utilities in Florida use operating and/or redispatch solutions to control overloads on their systems?

A. Yes. All utilities in Florida use operating and redispatch solutions to control overloads where possible on their systems. Their use results in lower total costs for customers in the state and is a very prudent action by the utilities. DEF makes extensive use of operating procedures and redispatch solutions on their system.

Q. Is Osprey limited to delivering only 249 MW of energy and capacity to the DEF BAA during all hours of a year?

A. No. During most hours of the year, Osprey can deliver up to the full 515 MW as proposed by Calpine's offer. It is only during certain specific conditions during the year, such as the peak load hours of the year, that Osprey is limited on the amount of energy and capacity that can be delivered without the use of operating procedures and/or redispatch of other DEF or TEC resources. When a request for firm PTP transmission service is made to a Transmission Service Provider, a study is completed under the most limiting conditions for granting the requested service. Generally this is during the summer and winter peak load conditions. In addition, certain sensitivities, which would include adverse conditions for providing the service, are studied. If any limitation is found for granting the service, even if for only one hour of the year, and the limitation cannot be mitigated by either an operating solution or construction of new facilities, then the requested service is denied. Generally, these limiting conditions only exist during the very peak load hours of each year or during certain stressed dispatch conditions. Outside of these very peak load hours, or under more normal dispatch conditions, additional energy and capacity can be delivered. This is the case for Osprey delivering to the DEF BAA. My evaluation of Osprey's ability to deliver energy and capacity to the DEF

BAA shows that with the use of operating procedures and/or redispatch solutions, and some possible minor 69 kV upgrades on the TEC system for double contingency outages, Osprey should be able to deliver 515 MW of capacity to DEF as a replacement for the Suwannee CTs and the Hines Chillers until January 1, 2020, the end of the PPA term offered by Calpine. After January 1, 2020, a long-term solution needs to be completed to avoid additional transmission constraints that begin to appear in the summer of 2020.

Q. What is the long-term solution for Osprey to deliver to DEF?

A. The long-term solution for Osprey is a direct connection of the plant to the DEF transmission system. This solution was evaluated by DEF as part of the asset purchase evaluation of Osprey and is summarized in Ed Scott's testimony in Docket No. 140111-EI, the docket that addresses DEF's Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018. This solution involves the construction of two new 230 kV lines from the Recker Substation to the DEF system. One line would be constructed from Recker to Duke's existing Kathleen Substation and the other line would be constructed from Recker to Duke's existing Haines City East Substation. According to Ed Scott's testimony, these lines and the new connection to DEF resolve not only the overloads on the DEF system, but also all of the overloads identified on the TEC system and the overloads identified on third party systems in FRCC.

Q. What is the cost of these new lines and the direct connection to the DEF system?

A. DEF estimates, in Ed Scott's testimony, that this new interconnection would cost approximately $150 million.

Q. Do you believe that this is a reasonable estimate of the cost for these new direct connection lines and facilities?

A. I believe that it is a typical planning estimate, based on a generic cost per mile for new 230 kV transmission lines. I believe that the actual cost of the direct connection facilities most likely will be less than the $150 million estimate. This is my opinion based on my experience and on my specific knowledge of how utilities, including Duke's predecessor, Florida Power Corporation, make their planning estimates. When reviewing various construction alternatives for future expansion of the transmission system, planning engineers need a quick method for comparing the cost of different options. The common way of doing this is to use a generic cost per mile for new transmission line construction at each voltage level. The cost per mile used is usually on the high side to give an upper bound for the cost of the new line. Once a specific option is chosen, a detailed site specific estimate is made, which is generally lower than the cost per mile estimate.

Q. What are the timing requirements for a direct connection to the DEF system?

A. Obviously, from the considerable benefits provided by the direct connection, the sooner the new lines are constructed and placed in service, the better. Assuming that the direct connection is not constructed until 2020, operating solutions or redispatch options would be required to mitigate some transmission facility overloads with Osprey delivering the full 515 MW to DEF prior to 2020. If DEF exercises the purchase option offered by Calpine, the new direct connection needs to be in service by January 1, 2020.

Q. Can this new interconnection be constructed in time to be placed in service by the needed date?

A. Yes. The required transmission lines are all within Polk County and are therefore not subject to the Florida Transmission Line Siting Act. The purchase option offered by Calpine allows DEF to purchase the Osprey Facility on January 1, 2020. Allowing for appropriate planning by DEF before exercising the purchase option, I believe these lines can be placed in service before the summer of 2018 if desired. In fact, in Ed Scott's testimony, he states that he believes the facilities required can be placed in service by the summer of 2017. (*See* the Direct Testimony of Ed Scott at 10.)

Q. How does this scenario fit with the transmission study, which was cited by DEF that TEC performed to provide the additional 266 MW of PTP transmission service from Osprey to DEF, and in which TEC estimated that upgrades totaling $169 million would be required on their system?

A. The TEC study that DEF's witness Ed Scott cited in Exhibit ES-3 to his direct testimony in Docket No. 140111-EI was done for transmission service starting in summer 2018 and continuing through the planning horizon. Since this covers a longer period and has to resolve overloads that show up in the later years, additional upgrades are required in those later years to mitigate all of the issues identified in the study. In addition, this study was completed with a smaller size combined cycle installation at Citrus County and the generation at Osprey further reduced the capacity installation at Citrus County. TEC did not study an additional 266 MW of transmission service from Osprey to DEF starting in summer of 2016. The scenario I have laid out in this testimony calls for Osprey to directly replace the Suwannee CTs in 2016 and the Hines Chillers in 2017. With the construction of a new direct connection of Osprey to the DEF transmission system, it is my opinion that the total cost of all required transmission upgrades to the FRCC grid through the planning horizon is no more than $150 million.

Q. Did DEF evaluate this scenario in its evaluation of alternative supply-side generation proposals to their self-build generation options?

A. No. To the best of my knowledge, from reviewing the testimony and submittals in these dockets, DEF did not evaluate an option of Osprey replacing the Suwannee CTs and the Hines Chillers through a PPA in 2015 followed by an asset purchase and a direct connection to the DEF system by 2020.

Q. Does the direct connection of Osprey to DEF provide any additional benefits to the transmission system?

A. Yes. To understand this, one needs to look at the design of the DEF transmission system. The 500 kV system on DEF consists of two radial lines, one starting at DEF's Crystal River station and running to the south, through Brookridge Substation and terminating at Lake Tarpon, and the other starting at Crystal River and running east, then south, through DEF's Central Florida Substation and terminating at Kathleen. An additional 500 kV line connecting the two ends of these circuits was originally planned to be constructed, creating a loop for the 500 kV system, but this project was abandoned in the 1990's due to escalating easement and right-of-way acquisition costs. DEF has two major load centers, one being the Florida Suncoast area (Pinellas, Pasco and Hernando Counties) and the other being the Central Florida area (Orange, Osceola, and Seminole Counties). The only significant transmission connections between these two load centers are through 230 kV connections on the far northern end of the Central Florida area to Central Florida Substation and then following the 500 kV lines through Crystal River and down to Lake Tarpon Substation. There is very limited transmission capability south out of Kathleen Substation back to the Florida Suncoast area due to a single 115 kV DEF line from Griffin to Higgins. This is an old line that was never intended to carry bulk power transfers between the radial ends of the 500 kV system. The Morgan Road Substation is planned to be added in this line in 2017. By directly connecting the Osprey Facility to the DEF transmission system through a 230 kV line from Recker to Kathleen and then from Recker to Haines City East, a southern 230 kV tie on the DEF transmission system is created between the two load centers. This will increase the reliability of the DEF transmission system and improve the deliverability of DEF generation to DEF load.

Q. Has DEF recognized this transmission reliability benefit in the analysis of a direct connection of Osprey to the DEF transmission system?

A. DEF mentioned this reliability benefit in the written testimony of Ed Scott, Scott Exhibit ES-3 at page 2 of 4, however no monetary value was placed on this transmission benefit.

Q. Are there any other transmission reliability benefits that the new CTs at Suwannee would provide to the DEF transmission system?

A. Yes, there may be a need for additional reactive supply and voltage support in the Suwannee area that would be provided by the new Suwannee CTs. This may be especially true if DEF retires the existing Suwannee steam units in 2018 as noted in the 2014 Ten Year Site Plan.

Q. If DEF uses Osprey to replace the planned capacity of the Suwannee CTs, are there other cost effective options for providing this reactive supply or voltage support?

A. Yes. While Osprey also supplies reactive power to the transmission system, it is not possible to move reactive power over long distances. Generally reactive power, or voltage support, has to be provided close to the point on the grid where it is needed. Voltage support can be provided at the Suwannee site in one of two ways: (1) either through the installation of static supply on the transmission system from capacitors, or (2) through the conversion of one or more of the existing steam units to synchronous condenser operation. An advantage of the synchronous condenser operation is that the reactive supply is then a dynamic supply, essentially the same as provided by a generating unit. In synchronous condenser operation, generally the prime mover of the generator is uncoupled and the generator is operated as a synchronous motor, spinning with no load. The field excitation is adjusted to control the reactive power flowing either out of or into the synchronous motor. In this manner the synchronous condenser can be used to either raise or lower the transmission system voltage, depending on the needs of the system. DEF could still retire the Suwannee steam units from electric production use and convert one or more of them to synchronous condenser operation to provide any voltage support needed at the Suwannee site.

Q. Is it reasonable to expect that using this synchronous condenser option, if necessary, would be more cost-effective for Duke and its customers than simply building the Suwannee CTs?

A. Yes. Synchronous condensers are a widely known and frequently used means of providing reactive power supply or voltage support. In Florida, FPL recently converted one of the steam turbine generators at its Turkey Point generating station to synchronous condenser operation to provide exactly these support benefits. FPL also plans to convert a second unit at Turkey Point to synchronous condenser operation in 2017. Excerpts from FPL's 2013 Ten Year Site Plan detailing these changes are found in Exhibit JS-2 to my direct testimony. The costs of such a conversion are minimal. The generator is uncoupled from the turbine and a reduced voltage starting mechanism is added to be able to bring the generator to synchronous speed. Ongoing costs include the O&M to maintain the generator in operating condition and the cost of losses during operation for the generator to spin at no load.

Q. Do you agree with the way DEF conducted the transmission evaluation of each proposal it received in response to the RFP?

A. No. In its evaluation, DEF took all of the individual proposals it received and then grouped them into various combinations to compare as different blocks of capacity which would compete with DEF's self-build options. One problem with this is that sufficient transmission capacity may exist for one proposal to deliver to DEF, but not for two similarly situated generation proposals. In that case, while one proposal evaluated by itself may be economic, when grouped together with other proposals, transmission upgrades may be required that would not have been necessary for an individual generator. Another problem is that since transmission upgrades are "lumpy" (i.e., such upgrades can only be added in large, discrete blocks of capacity, such as the amount of power that can be carried over a 230 kV circuit rather than in small increments), a proposal considered by itself may require a reasonable or cost effective set of upgrades, but when grouped together with other proposals also requiring upgrades, the next increment of upgrade may be much more expensive and make the entire group of proposals no longer economic.

Q. How should DEF have conducted the transmission evaluation?

A. In my opinion, the most appropriate way for DEF to conduct the transmission evaluation of the proposals it received would have been to evaluate each offer individually. Transmission expansion costs associated with the delivery of energy and capacity from each facility offered would be included in the total evaluated price of the proposal and would then be coupled with a corresponding optimum self-build option which would result in the net capacity increase needed to meet DEF's load serving obligation. In this manner, the optimum generation expansion plan is developed by combining the most economic offers received in response to the RFP with DEF's own most economic self-build option or options. DEF's customers receive the greatest benefit in this instance as well, since the truly lowest cost expansion plan results.

Q. Please summarize the main conclusions of your testimony.

A. Calpine's Osprey Facility is well positioned to replace the Suwannee CTs and the Hines Chillers proposed by DEF. From a transmission perspective, Osprey can begin delivering energy and capacity to DEF through firm PTP transmission service starting in 2015. Operating procedures, redispatch solutions and/or minor 69 kV construction can be utilized to mitigate any transmission constraints until new direct connection transmission facilities are constructed to allow the full capacity of Osprey to be fully integrated into the DEF transmission system by January 1, 2020 or earlier if so desired by DEF. DEF did not evaluate the ability of Osprey to replace the Suwannee CTs and the Hines Chillers through a 5-year PPA followed by an asset purchase with a direct transmission connection. The direct connection provides ancillary transmission system benefits resulting in a reliable and cost effective addition to the DEF system.

Q. Does this conclude your testimony?

A. Yes, it does.

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TRANSMISSION CONSULTANT

Improved transmission access capability for generating plants by upgrading transmission interconnection rights through new generator interconnection requests. Provided transmission expertise to determine and implement highest value interconnection arrangements.

Directed the development of a power system model for forecasting transmission congestion, reductions in transmission transfer capabilities, and impacts on nodal prices.

Has appeared as an expert witness, provided expert testimony, and served as a speaker on Federal Regulatory Issues related to open access transmission, eminent domain, and generator reactive power tariffs.

Negotiated the Standard Large Generator Interconnection Procedures and Large Generator Interconnection Agreement with Transmission Providers and other Independent Generators as part of FERC's rule making process leading to FERC Order 2003.

Secured approval of the first significant modification to the FERC pro forma open access transmission tariff for an individual utility, i.e., the addition of Network Contract Demand Transmission Service. Recognized as the company's expert on federal regulatory issues related to open access transmission.

PROFESSIONAL EXPERIENCE

JOHN L. SIMPSON TRANSMISSION CONSULTING — April 2011 to Present

CONSULTANT
Provide transmission consulting services to independent power producers and exempt wholesale generators on transmission access and congestion issues. Provide transmission and generation related expertise on FERC regulatory and NERC compliance matters.

RRI ENERGY, INC./GENON ENERGY, INC. — June 2008 to April 2011

MANAGER, TRANSMISSION POLICY
Provide transmission technical expertise and support to Commercial and Plant Operations to enable commercial opportunities and improve plant efficiency. Proactively influence transmission policy favorable to RRI by representing RRI on NERC and Regional Reliability Organization committees. Identify and evaluate opportunities to optimize transmission services to benefit the RRI generation fleet.

CONSULTANT — May 2007 to June 2008

Provide consulting services to Reliant Energy on generator interconnection, transmission service, and merchant generator power sales projects. Represent Reliant Energy on NERC and RRO committees and task forces.

RELIANT ENERGY, INC. — November 1999 to May 2007

DIRECTOR, TRANSMISSION ANALYSIS
Direct the Transmission Analysis Department activities in support of Trading, Power Origination, and Generation Development. Provide overall transmission strategy to maximize value of generation assets for Reliant Energy Power Generation. Direct the preparation of forecasts of transmission congestion and changes

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PROFESSIONAL EXPERIENCE

RELIANT ENERGY, continued
in transmission transfer capabilities in ERCOT and PJM. Direct transmission studies to assess the capabilities of the transmission system to support new generation development and power sales from existing and planned new generation. Negotiate Generator Interconnection Agreements with Transmission Providers. Provide technical support to Trading for Transmission Service Requests and Agreements. Monitor transmission related filings at FERC and direct the preparation and filing of Interventions and Protests in appropriate dockets.

FLORIDA POWER CORPORATION — February 1985 to November 1999

Various positions of increasing responsibility in electric utility engineering management as follows:

DIRECTOR, SYSTEM PLANNING — March 1995 to November 1999

Direct the planning activities for all transmission, substation, and major distribution facility additions on the Florida Power Corporation (FPC) system. Includes the formulation of a technical and economic plan that provides for transmission, substation, and distribution facility additions to meet the electrical needs of wholesale and retail customers of FPC. Capital Budget developed and administered is $50 million annually. Responsible for the administration of FPC's open access transmission tariff and the development of transmission policy and strategies to achieve the desired results.

MANAGER, TRANSMISSION DESIGN — November 1988 to March 1995

Managed the overall project activities for the engineering, design, permitting, right-of-way acquisition, material procurement, and construction specifications for new transmission lines and modifications to existing transmission lines from 69 kV to 500 kV. Testified as FPC's expert witness in eminent domain proceedings.

MANAGER, RELAY DESIGN — August 1987 to November 1988

SUPERVISOR, TRANSMISSION AND SUBSTATION STANDARDS — February 1985 to August 1987

PUBLIC SERVICE COMPANY OF COLORADO — June 1972 to January 1985

Various positions of increasing responsibility in electric utility engineering and supervision including:

SUPERVISOR, SYSTEM PROTECTION ENGINEERING
SUPERVISOR, SUBSTATION ENGINEERING
SUPERVISOR, PLANT ELECTRICAL ENGINEERING
VARIOUS ENGINEERING POSITIONS

EDUCATION

Bachelor of Science Degree - Electrical Engineering - University of Colorado - 1972

Member: Sigma Tau-Tau Beta Pi - Engineering Honor Society
Eta Kappa Nu - Electrical Engineering Honor Society

Registered Professional Engineer - States of Colorado and Florida

Executive Education - The Wharton School - University of Pennsylvania - 1997
Strategic Thinking and Management

FPL

Ten Year Power Plant Site Plan

2013-2022

Submitted To:

**Florida Public
Service Commission**

**Miami, Florida
April 2013**

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Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2012)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie [1]	Hutchinson Island, FL	2	Nuclear	1,832
Turkey Point	Florida City, FL	2	Nuclear	1,501
Total Nuclear:		4		3,333
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	642
St. John's River Power Park [2]	Jacksonville, FL	2	Coal	254
Total Coal Steam:		3		896
Combined-Cycle [3]				
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,079
Sanford	Lake Monroe, FL	2	Gas	1,946
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		15		12,755
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,621
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades	Port Everglades, FL	2	Oil/Gas	761
Turkey Point [4]	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam:		8		4,822
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		48		1,908
Combustion Turbines [3]				
Fort Myers	Fort Myers, FL	2	Gas/Oil	316
Total Combustion Turbines:		2		316
PV				
DeSoto [5]	DeSoto, FL	1	Solar Energy	25
Space Coast [5]	Brevard County, FL	1	Solar Energy	10
Total PV:		2		35
Total System Generation as of December 31, 2012 =		82		24,065
System Firm Generation as of December 31, 2012 =		80		24,030

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 843/862. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).

3/ The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.

4/ Turkey Point 2 is currently operating as a synchronous condenser. If needed, can be converted back to a generating unit per the existing Title V operating permit through the end of 2013 and is not accounted for in Reserve Margin Calculation.

5/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.

being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop the current resource plan. This plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2013 through 2022 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions that primarily consist of: (i) changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls and through other uprates to existing capacity), (ii) changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, (iii) the modernizations of FPL's existing Cape Canaveral, Riviera Beach, and Port Everglades sites by the removal of the steam

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes for FPL (1)			
Year	Projected Capacity Changes	Net Capacity Changes (MW) Winter (2)	Summer (3)
2013	Changes to Existing Purchases (4)	(545)	(425)
	Port Everglades Units 3 & 4 retired for Modernization	(765)	(761)
	Turkey Point Unit 2 operation changed to synchronous condenser	(394)	(392)
	Sanford Unit 5 CT Upgrade	—	9
	Turkey Point Unit 4 Uprate - Completed	—	115
	Turkey Point Unit 4 Uprate - Outage (5)	(717)	—
	Sanford Unit 4 CT Upgrade	—	16
	Manatee Unit 2	(3)	—
	Scherer Unit 4	(28)	—
	Cape Canaveral Next Generation Clean Energy Center (6)	—	1,210
	Manatee Unit 1 ESP - Outage (7)	(822)	—
	Martin Unit 1 ESP - Outage (7)	—	(826)
2014	Sanford Unit 5 CT Upgrade	19	10
	Cape Canaveral Next Generation Clean Energy Center (6)	1,355	—
	Changes to Existing Purchases (4)	22	37
	Manatee Unit 1 ESP - Outage (7)	822	—
	Sanford Unit 4 CT Upgrade	16	—
	Vero Beach Combined Cycle (8)	46	44
	Martin Unit 1 ESP - Outage (7)	(832)	826
	Martin Unit 2 ESP - Outage (7)	—	(826)
	Manatee Unit 3 CT Upgrade	—	19
	Turkey Point Unit 5 CT Upgrade	—	33
	Turkey Point Unit 4 Uprate - Completed (5)	115	—
	Riviera Beach Next Generation Clean Energy Center (6)	—	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Martin Unit 1 ESP - Outage (7)	832	—
	Martin Unit 2 ESP - Outage (7)	—	826
	Turkey Point Unit 5 CT Upgrade	33	—
	Changes to Existing Purchases (4)	70	70
	Ft. Myers Unit 2 CT Upgrade	—	51
	Riviera Beach Next Generation Clean Energy Center (6)	1,344	—
2016	Changes to Existing Purchases (4)	(858)	(928)
	Ft. Myers Unit 2 CT Upgrade	51	—
	Port Everglades Next Generation Clean Energy Center (6)	—	1,277
2017	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	(396)
	Changes to Existing Purchases (4)	(37)	(37)
	Vero Beach Combined Cycle (8)	(46)	(44)
	Port Everglades Next Generation Clean Energy Center (6)	1,429	—
2018	Changes to Existing Purchases (4)	(388)	(381)
2019	—	—	—
2020	—	—	—
2021	Changes to Existing Purchases (4)	180	180
2022	Turkey Point Nuclear Unit 6 (6)	—	1,100

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) Outages for uprate work.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(7) Outages for ESP work.
(8) This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.