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FPSC - COMMISSION CLERK

Docket No. 150043-EI
Comprehensive Exhibit List for Entry into Hearing Record
June 3, 2015

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF				
1		Exhibit List	Comprehensive Exhibit List	
DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)				
2	Mark E. Landseidel	MEL-1	A map showing the location of the Suwannee power plant site in Suwannee County, Florida.	**Stipulated**
3	Mark E. Landseidel	MEL-2	The preliminary layout of the Suwannee Simple Cycle project at the Suwannee power plant site.	**Stipulated**
4	Mark E. Landseidel	MEL-3	An itemization of the major cost items for the Suwannee Simple Cycle project.	**Stipulated**
5	Mark E. Landseidel	MEL-4	CONFIDENTIAL – The projected schedule for completion of the Suwannee Simple Cycle project.	**Stipulated**
6	Edward L. Scott	ELS-1	CONFIDENTIAL – A copy of Mr. Scott's May 27, 2014 Direct Testimony and Exhibits filed in Docket No. 140111-EI, In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	**Stipulated**

7	Kevin E. Delehanty	KED-1	CONFIDENTIAL – A copy of Mr. Delehanty's May 27, 2014 Direct Testimony filed in Docket No. 140111-EI in re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc., along with Exhibit Nos. ___ (KD-1) through (KD-4).	**Stipulated**
8	Kevin E. Delehanty	KED-2	CONFIDENTIAL – A chart of the Company's base, high, and low natural gas price forecast.	**Stipulated**
9	Kevin E. Delehanty	KED-3	CONFIDENTIAL – A chart of the Company's base natural gas price forecast and other industry natural gas price forecasts.	**Stipulated**
10	Kris G. Edmondson	KGE-1	A map showing the location of the Osprey Energy Center in Auburndale, Polk County, FL.	**Stipulated**
11	Kris G. Edmondson	KGE-2	CONFIDENTIAL – The Technical Due Diligence Evaluation report for the Osprey Energy Center prepared by Burns & McDonnell Engineering Company, Inc.	**Stipulated**
12	Kris G. Edmondson	KGE-3	CONFIDENTIAL – The Pro Forma Maintenance Cost Summary Projections for the Osprey Plant.	**Stipulated**
13	Matthew E. Palasek	MEP-1	CONFIDENTIAL – The August 25, 2014 term sheet between DEF and Calpine for DEF's acquisition of the Osprey Plant.	**Stipulated**
14	Matthew E. Palasek	MEP-2	CONFIDENTIAL – The APA between DEF and Calpine for DEF's acquisition of the Osprey Plant, including Amendments 1, 2, 3, and 4.	**Stipulated**

15	Benjamin M.H. Borsch	BMHB-1	CONFIDENTIAL – A composite exhibit of (i) Mr. Borsch's direct testimony and exhibits and (ii) the direct testimony and exhibits of DEF's expert Julie Solomon, who performed the FERC Competitive Analysis Screen qualitative analysis for DEF's evaluation of generation alternatives to meet its need prior to 2018, filed with the Commission in Docket No. 140111-EI on May 27, 2014.	**Stipulated**
16	Benjamin M.H. Borsch	BMHB-2	CONFIDENTIAL – A composite exhibit of (i) Mr. Borsch's rebuttal testimony and exhibits and (ii) the rebuttal testimony and exhibits of DEF's expert Julie Solomon, who performed the FERC Competitive Analysis Screen qualitative analysis for DEF's evaluation of generation alternatives to meet its need prior to 2018, filed with the Commission in Docket No. 140111-EI on August 5, 2014.	**Stipulated**
17	Benjamin M.H. Borsch	BMHB-3	The Company's final detailed economic analysis results that demonstrate the Osprey Plant acquisition is a more cost-effective generation alternative than the Suwannee Simple Cycle Project, if the requisite regulatory approvals for the Osprey Plant acquisition are obtained in accordance with the terms of the Asset Purchase and Sale Agreement between DEF and Calpine.	**Stipulated**

18	Benjamin M.H. Borsch	BMHB-4	The Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017.	**Stipulated**
STAFF				
19		Staff's Exhibit #19	DEF's Responses to Staff's First Set of Interrogatories (Nos. 2-5, 6 **(CONFIDENTIAL),** 11, 13, and 20-30) *[Bates Nos. 00001-00071]*	**Stipulated**
20		Staff's Exhibit #20	DEF's Supplemental Responses to Staff's First Set of Interrogatories (Nos. 11b and 11c) *[Bates Nos. 00072-00077]*	**Stipulated**
21		Staff's Exhibit #21	DEF's Responses to Staff's Second Set of Interrogatories (Nos. 31-35) *[Bates Nos. 00078-00092]*	**Stipulated**
22		Staff's Exhibit #22	DEF's Responses to Staff's Third Set of Interrogatories (No. 42) *[Bates Nos. 00093-00096]*	**Stipulated**
23		Staff's Exhibit #23	DEF's Supplemental Responses to Staff's Third Set of Interrogatories (Nos. 36-40) *[Bates Nos. 00097-00111]*	**Stipulated**
24		Staff's Exhibit #24	DEF's Responses to Staff's Fourth Set of Interrogatories (Nos. 45-46) *[Bates Nos. 00112-00116]*	**Stipulated**
25		Staff's Exhibit #25	DEF's Responses to Staff's First Request for Production of Documents (Nos. 12 and 13) **See Staff Exhibit CD for the responsive Excel files.** *[Bates Nos. 00117-00119]*	**Stipulated**

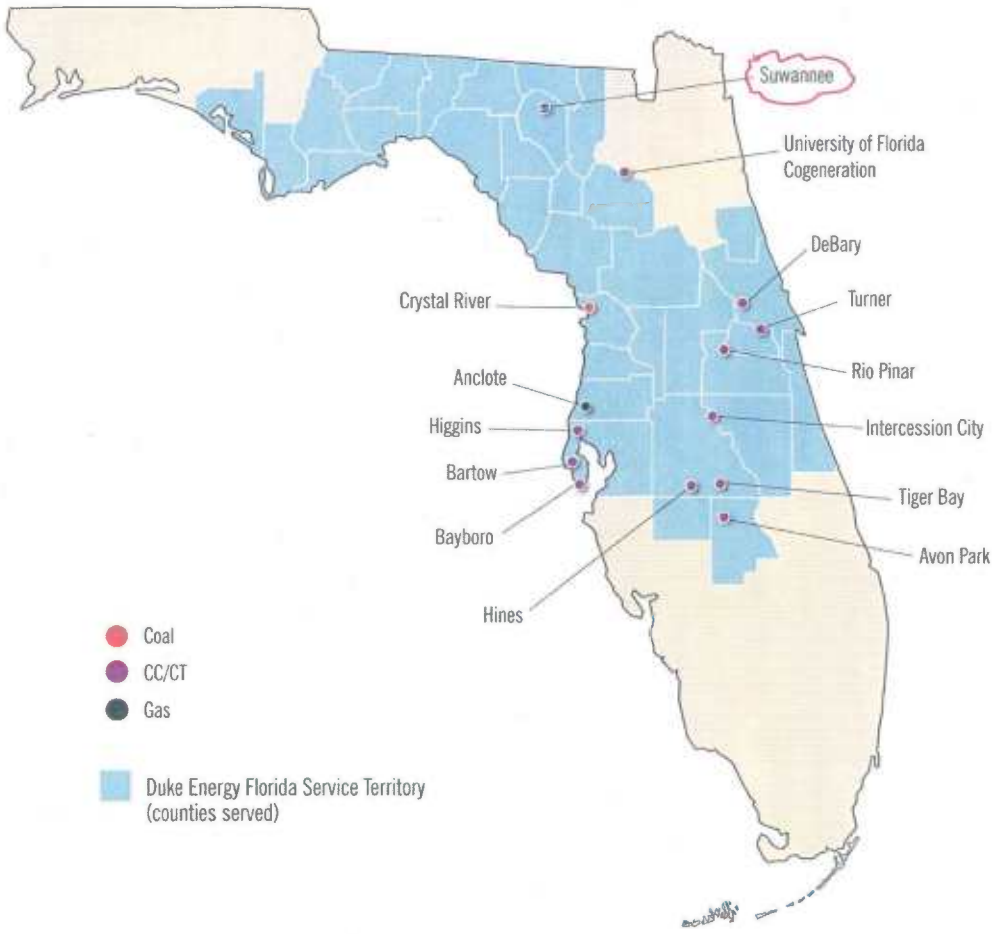
26		Staff's Exhibit #26	DEF's Responses to Staff's Second Request for Production of Documents (Nos. 14 (**CONFIDENTIAL)** and 19-20) **See Staff Exhibit CD for the responsive Excel files.** *[Bates Nos. 00120-00124]*	**Stipulated**
27		Staff's Exhibit #27	DEF's Supplemental Responses to Staff's Third Request for Production of Documents (Nos. 22-24) *[Bates Nos. 00125-00129]*	**Stipulated**
28		Staff's Exhibit #28	DEF's Responses to Staff's Fourth Request for Production of Documents (No. 25) **See Staff Exhibit CD for the responsive Excel files.** *[Bates Nos. 00130-00137]*	**Stipulated**

OTHER HEARING EXHIBITS

Exhibit Number	Witness	Party	Description	Moved In/Due Date of Late Filed
29		Staff	Proposed Stipulation of Issues	**Stipulated**

Docket No. _____
Duke Energy Florida
Exhibit No. ____ (MEL-1)

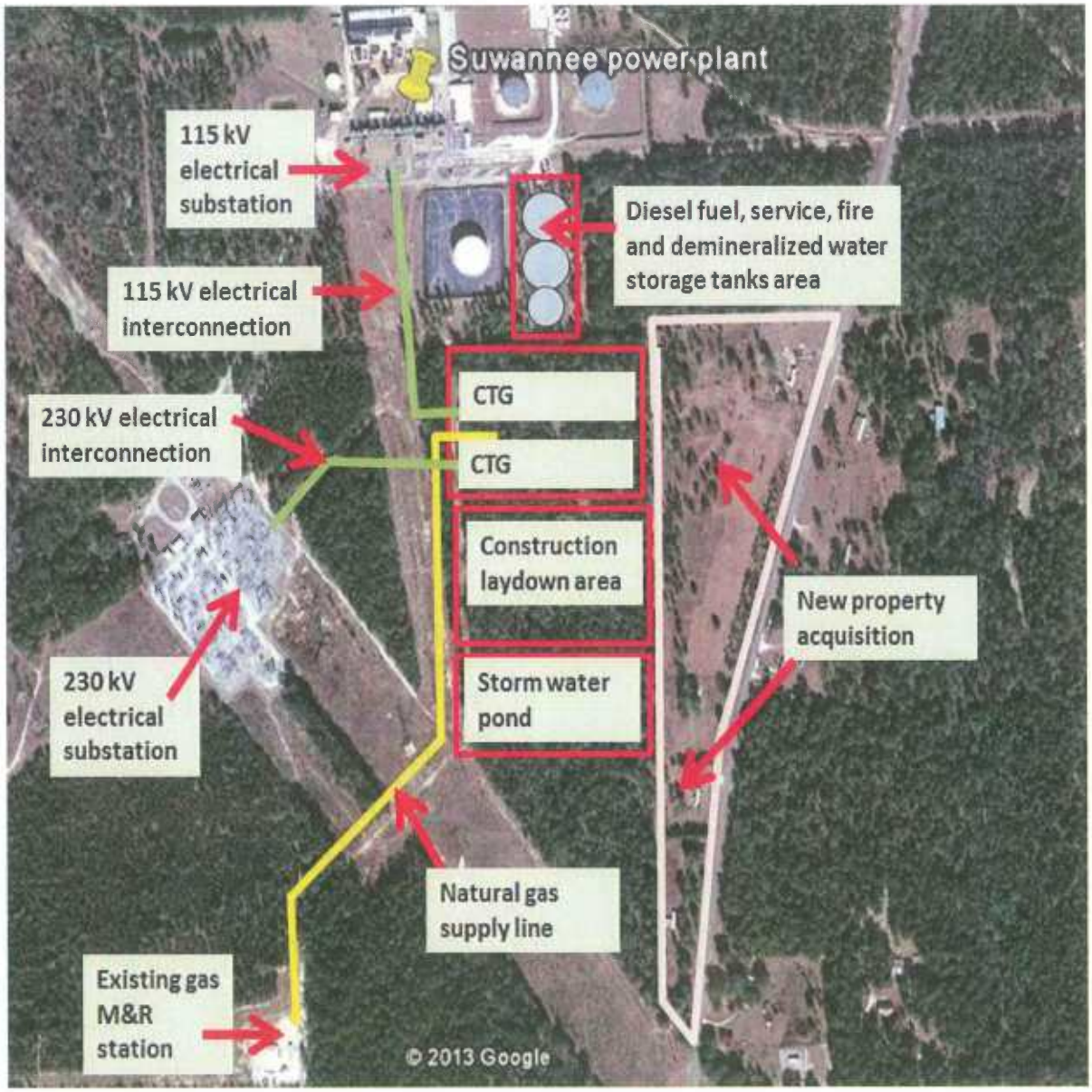
Map Showing Location of Suwannee Power Plant Site



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 2
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-1

DOCKET NO. _____
DUKE ENERGY FLORIDA
EXHIBIT NO. ____ (MEL-2)
PAGE 1 of 1

Preliminary layout of the Suwannee Simple Cycle project



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 3
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-2

Itemization of the major cost items

Estimate Category	$ Million
Major Equipment and Engineering, Procurement and Construction (EPC)	$134
Owners Costs including Transmission and Contingency	$43
Subtotal Project Estimate	**$177**
AFUDC	$18
Total Project Cost	**$195**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 4
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-3

REDACTED

Projected Schedule

Key Project Milestone	Date
BOD Approval	December 2014
FPSC Need Filing	January 2015
FPSC Need Approval	May 2015
Receive Air Permit	June 2015
[redacted]	[redacted]
Start EPC Contractor	
Start CTG and GSU Suppliers	
EPC Begin Construction	
CTG Site Delivery	
Mechanical Completion	
First Fire	
Commercial Operation	June 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 5
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-4

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. _____
Submitted for filing:
May 27, 2014

DIRECT TESTIMONY OF ED SCOTT

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 6
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Edward L. Scott ELS-1

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

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. _____

DIRECT TESTIMONY OF ED SCOTT

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Ed Scott and I am employed by Duke Energy Florida, Inc. ("DEF" or the "Company"). My business address is 6565 38th Avenue, North, St. Petersburg, Florida 33710.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director --- Transmission Planning Florida. In this role, I am responsible for all transmission planning for DEF. I am responsible for ensuring that long-range transmission plans, studies, and assessments are performed in accordance with all applicable Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC"), Florida Reliability Coordinating Council ("FRCC"), and DEF planning standards and requirements. Areas of additional focus include development of Generation and Transmission Integrated Siting Strategies and evaluation

of Transmission Service and Generator Interconnection Requests. I also represent DEF on the FRCC Planning Committee and the NERC Planning Committee.

Q. Please summarize your educational background and employment experience.

A. I have been with the Company (and its predecessor companies Progress Energy Florida and Florida Power Corp.) since 2001 in positions of increasing responsibility. In my previous role as Manager of System Operations at the Florida Energy Control Center, I oversaw the real time, electric system operations of the Florida utility, including generation dispatch, transmission reliability, and transmission service transactions. I have held prior leadership roles as Manager of Bulk Transmission Planning, and Supervisor System Operations for the Company. I also held several Company engineering positions with increasing responsibility in Operations Network Reliability, Operations Planning, and Operations Training. Prior to joining the Company, I was a staff engineer with the FRCC.

I earned bachelor and master of science degrees in electrical engineering from the Florida Institute of Technology in 1998 and 1999. I also earned a master of science degree in business administration from the University of Florida in 2007. I am a licensed Professional Engineer in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of the Company in support of its Petition for Determination of Cost Effective Alternative to Meet Need Prior to 2018 for Duke Energy Florida. I will

provide an overview of the transmission system impacts and costs for the generation options that the Company proposes to build to meet its need prior to 2018 in the most cost-effective manner for its customers. I will also address the transmission system impacts associated with supply-side generation alternatives that the Company evaluated to determine that the Company's self-build generation options are the most cost-effective resource options to meet the Company's need prior to 2018.

Q. Are you sponsoring any exhibits to your testimony?

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

- Exhibit No. ___ (ES-1), a map and graphic illustration of the transmission interconnections for the Suwannee Simple Cycle Project at the Suwannee power plant site;
- Exhibit No. ___ (ES-2), a depiction of the existing Hines Energy Complex ("HEC") combined cycle power plant blocks and the existing transmission interconnections; and
- Exhibit No. ___ (ES-3), a confidential description of the potential generation facility acquisitions evaluated for transmission cost impacts to the DEF transmission system, including the physical location of the facilities and a description of the necessary transmission network upgrades to reliably integrate the facilities onto the electric grid that result from the DEF transmission analyses.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. There is minimal transmission investment required to incorporate on DEF's system the Company's self-build generation options to meet its need prior to 2018. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate project are both located at existing DEF power plant sites. The location of these projects at the existing Suwannee and HEC power plant sites allows the Company to obtain substantial, additional summer generation capacity with relatively little additional transmission investment. As a result, there are transmission cost-savings benefits to customers resulting from the addition of these generation projects at existing Company power plant sites compared to Greenfield sites incorporated into the total cost of the projects.

The Company evaluated alternative power purchase agreement ("PPA") and generation facility acquisition options to meet its need prior to 2018. The impact of all of these alternative generation proposals on DEF's transmission system was evaluated. Two potential generation facility acquisitions were evaluated further to determine the transmission system network upgrades required to incorporate the generation facilities into the DEF system. The transmission system network upgrade costs to incorporate one of the potential generation facilities into DEF's system were substantial. The transmission costs associated with the potential generation facility acquisitions were included in the Company's economic evaluation of the most cost-effective option for the Company to meet its reliability need prior to 2018.

III. TRANSMISSION ANALYSIS OF COMPANY SELF-BUILD GENERATION OPTIONS.

Q. What are the Company's self-build generation options to meet its need before 2018?

A. The Company's self-build generation options are the Suwannee Simple Cycle Project in the summer of 2016 and the Hines Chillers Power Uprate Project in the summer of 2017. The Suwannee Simple Cycle Project involves the construction of two F class combustion turbines and related equipment and facilities at the Company's existing Suwannee power plant site in Suwannee County, Florida. The Suwannee Simple Cycle Project will total 320 MegaWatts ("MW") and it will be placed in commercial operation by June 2016. The Hines Chillers Power Uprate Project involves the installation of a chiller system designed to cool the gas turbine inlet air to all four existing natural-gas fired, combined cycle generation power blocks at the Company's HEC in Polk County, Florida. The Hines Chillers Power Uprate Project is projected to increase the summer HEC site capacity by 220 MW and this project will be in commercial operation by the summer of 2017. These projects are described in more detail in the direct testimony of Mr. Landseidel in this proceeding.

Q. What transmission analyses were performed for the Company's self-build generation options?

A. DEF performed transmission planning analyses in accordance with all applicable Federal Energy Regulatory Commission ("FERC"), NERC, FRCC, and DEF planning standards and requirements, for the proposed self-build generation option in Suwannee County, Florida. In addition, the same planning standards and requirements were applied to the

transmission analysis performed for the Hines Chillers Power Uprate Project. These transmission analyses include, as necessary, thermal load flow, stability, and short-circuit analyses to identify any need for additional transmission network upgrades to reliably integrate the proposed additional generation to the grid. For the proposed self-build generation option in Suwannee County, Florida, DEF performed an Interconnection Study to determine the impact of interconnecting the queued generation to the transmission system. These studies involved transmission contingency, short circuit, and stability analyses. For the proposed Hines Chillers Power Uprate Project a transmission evaluation was also performed which compared the original Hines Unit interconnection transmission infrastructure to any potential needs due to the proposed power uprate.

Q. What were the results of these transmission analyses?

A. The Suwannee Simple Cycle Project is located at the Company's existing Suwannee plant site located in Suwannee County, Florida. The two combustion turbines and two generator step-up transformers will be connected to the existing transmission switchyard at the site. One combustion turbine generator will be connected to the 115 kV transmission switchyard and the other combustion turbine generator will be connected to the 230 kV switchyard. Exhibit No. ___ (ES-1) is a map and graphic illustration of the transmission interconnections for the Suwannee Simple Cycle Project at the Suwannee power plant site. Our transmission analysis indicates transmission network upgrades estimated at $15.7 million are needed to reliably integrate the proposed additional generation to the grid.

The Company plans to retire the existing Suwannee steam units located at the

Suwannee power plant site when the Suwannee Simple Cycle Project is complete and the new combustion turbines achieve commercial operation. The existing steam units that will be retired are also depicted on the map in Exhibit No. ___ (ES-1) to my direct testimony. As a result, the combined net impact to the DEF system and electric grid of these retirements and the addition of the Suwannee Simple Cycle combustion turbines require minimal additional transmission network upgrades of the DEF transmission system to accommodate the generation for the Suwannee Simple Cycle combustion turbines.

The increase in summer capacity at the HEC site as a result of the Hines Chillers Power Uprate Project will not require additional transmission network upgrades on the DEF system. Likewise, because the HEC combined cycle power block units are already connected to the DEF transmission system, there are no generator interconnection costs associated with the Hines Chillers Power Uprate Project. The existing HEC combined cycle power plant block units and the existing transmission interconnections are shown in Exhibit No. ___ (ES-2) to my direct testimony.

Q. Do the customers benefit from the location of these self-generation projects at existing DEF generation sites?

A. Yes, from a transmission perspective, there are cost-saving benefits to customers resulting from the addition of these Company generation projects at existing sites. As I have explained above, the location of these projects at the existing Suwannee and HEC power plant sites, respectively, allows the Company to obtain substantial, additional summer capacity generation with relatively little additional transmission investment. The

existing transmission infrastructure at both sites supports the addition of the increased summer generation capacity from these projects.

Q. In your opinion, are the results of your analysis of the transmission costs for the Company's self-build generation plan projects reasonable?

A. Yes. In my professional opinion, and based on my experience and evaluation of the impact of adding these self-build generation plan projects to the Company's system, these results are accurate and reasonable.

IV. TRANSMISSION ANALYSIS OF THE SUPPLY-SIDE GENERATION ALTERNATIVES.

Q. Did the Company evaluate any alternative supply-side generation proposals to the Company's self-build generation options to meet the Company's generation needs before 2018?

A. Yes. The Company evaluated power purchase agreements ("PPAs") with existing generators or utilities and the potential acquisition of existing generators within Florida as alternatives to the Company's Suwannee Simple Cycle and Hines Chillers Power Uprate projects.

Q. Were transmission studies performed for these alternative supply-side generation proposals?

A. Yes. DEF performed a transmission screening study for all alternative supply-side generation proposals. The proposed PPAs and generation facility acquisitions were

evaluated to explore existing and alternative transmission solutions to reliably integrate the resources into the grid. In addition, potential impacts to third party systems were identified that were consistent with the results of previously performed transmission studies.

Q. What potential generation acquisitions were evaluated?

A. Two of the five proposed generation facility acquisitions passed the initial generation economic screening and they were evaluated further for their cost impacts to the DEF transmission system. These two proposed acquisitions are confidential and, accordingly, they are identified in confidential Exhibit No. ___ (ES-3) to my direct testimony. Exhibit No. ___ (ES-3) also identifies the physical location of these potential generation facility acquisitions and contains a description of the necessary transmission network upgrades to reliably integrate those resources onto the grid. For one potential acquisition, an alternative interconnection solution was studied to provide an alternative solution that potentially resolved all previously identified third party transmission impacts, and was reasonable to be placed in service by summer 2017.

Q. What transmission analyses were performed for these two alternative supply-side generation acquisition proposals?

A. The transmission screening studies were industry-standard studies consistent with DEF's internal standards and both FRCC and NERC reliability standards. The latest available FRCC peak load flow case, including the latest available information, was used as the baseline to determine what transmission system network upgrade facilities or

modifications were needed. The cost estimates were also based on industry-standard transmission facility estimation standards consistent with DEF's experience with such transmission facilities. DEF employed the same industry-standard transmission facility cost estimation standards to the alternative supply-side generation proposals that DEF uses for all of its planned or projected transmission facility additions or upgrades on its own transmission system. The results of these transmission screening studies indicated either no adverse transmission impacts, or third party impacts. As a result, alternative interconnection options, alternative DEF transmission network upgrades, and reasonable third party network upgrades were assumed as potential solutions. All potential solutions were then subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution.

Q. What were the results of these transmission analyses?

A. Transmission system network upgrades were required to incorporate one potential generation facility acquisition into the DEF system. These transmission system network upgrades are described more fully in Exhibit No. ___ (ES-3) to my direct testimony. The cost of these transmission system network upgrades were estimated at $150 million. DEF further estimated that permitting and construction for the transmission system network upgrades could be completed in time to meet the Company's need for additional generation prior to 2018.

The location of the other, potential generation facility acquisition that was evaluated resulted in minimal transmission system network upgrade costs, primarily on third party transmission systems. Approximately $15 million was estimated for these third party transmission system network upgrades to incorporate this potential generation

facility into DEF's system.

Q. Were the results of these transmission analyses incorporated into the Company's evaluation of the alternative supply-side generation proposals?

A. Yes. The transmission costs associated with the potential generation facility acquisitions, as well as the potential PPAs, were included in the economic evaluation of the most cost-effective option for the Company to meet its reliability need prior to 2018. The results of this economic evaluation are explained in detail in the Mr. Borsch's testimony in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

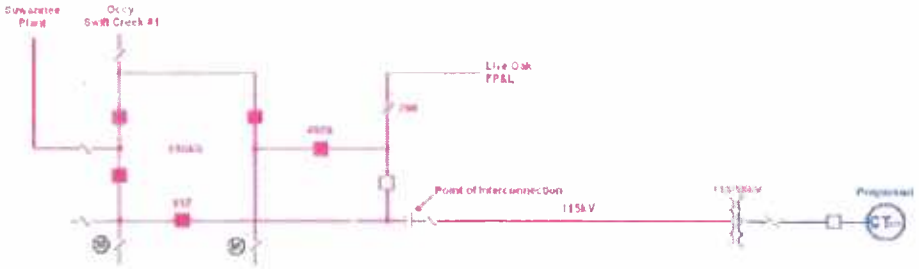
Interconnection Points Evaluated

Point of interconnection requested for study by interconnection customer for the 115kV unit:

- Connection to DEF's existing 115 kV Suwannee River Substation.

Alternative point of interconnection considered by DEF for the 115 kV unit:

- No other options were considered reasonable or necessary.

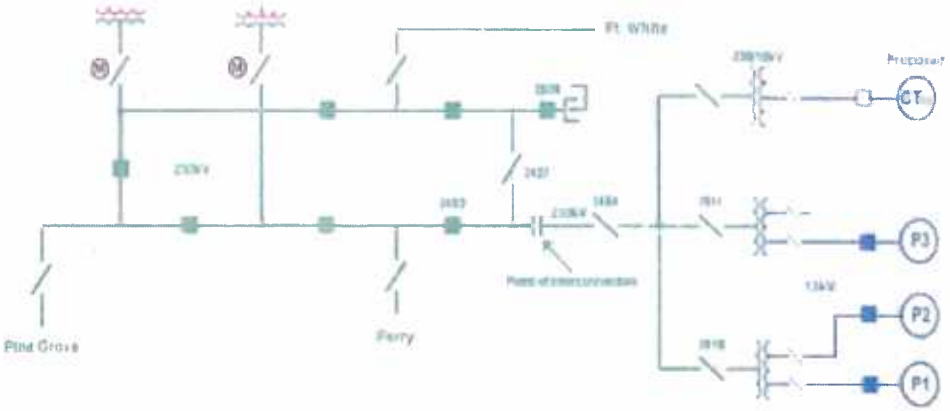


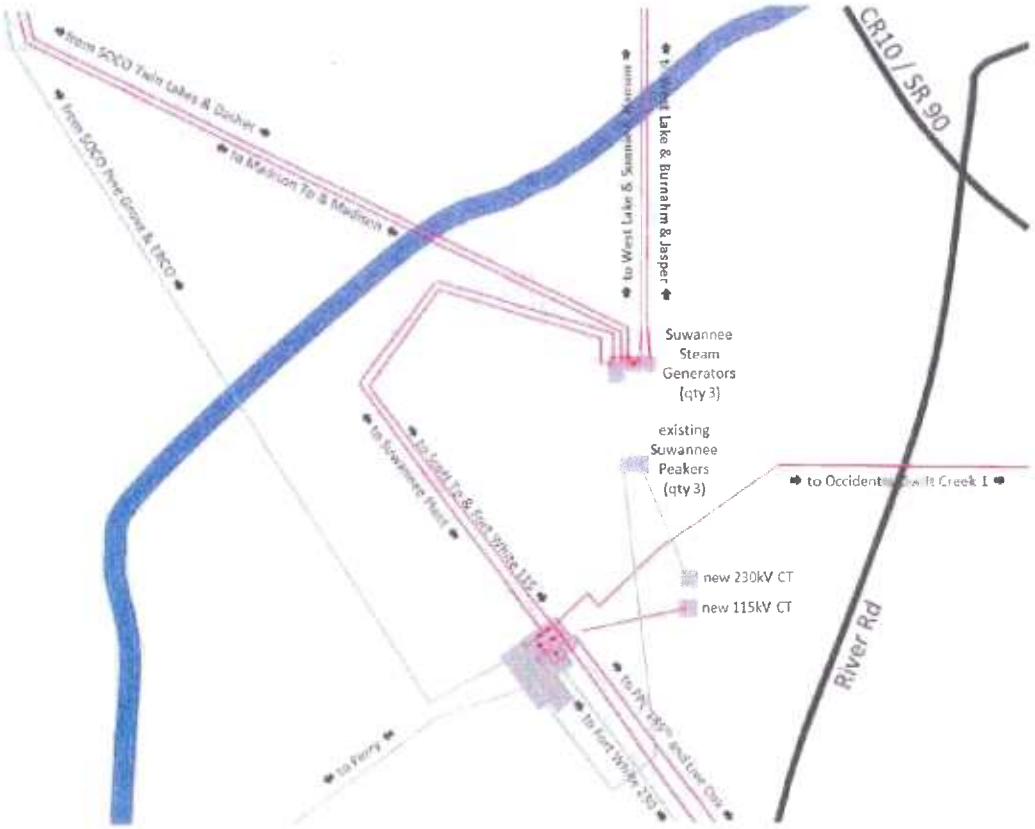
Point of interconnection requested for study by interconnection customer for the 230kV unit:

- Connection to DEF's existing Suwannee Peakers 230 kV switchyard..

Alternative point of interconnection considered by DEF for the 230 kV unit:

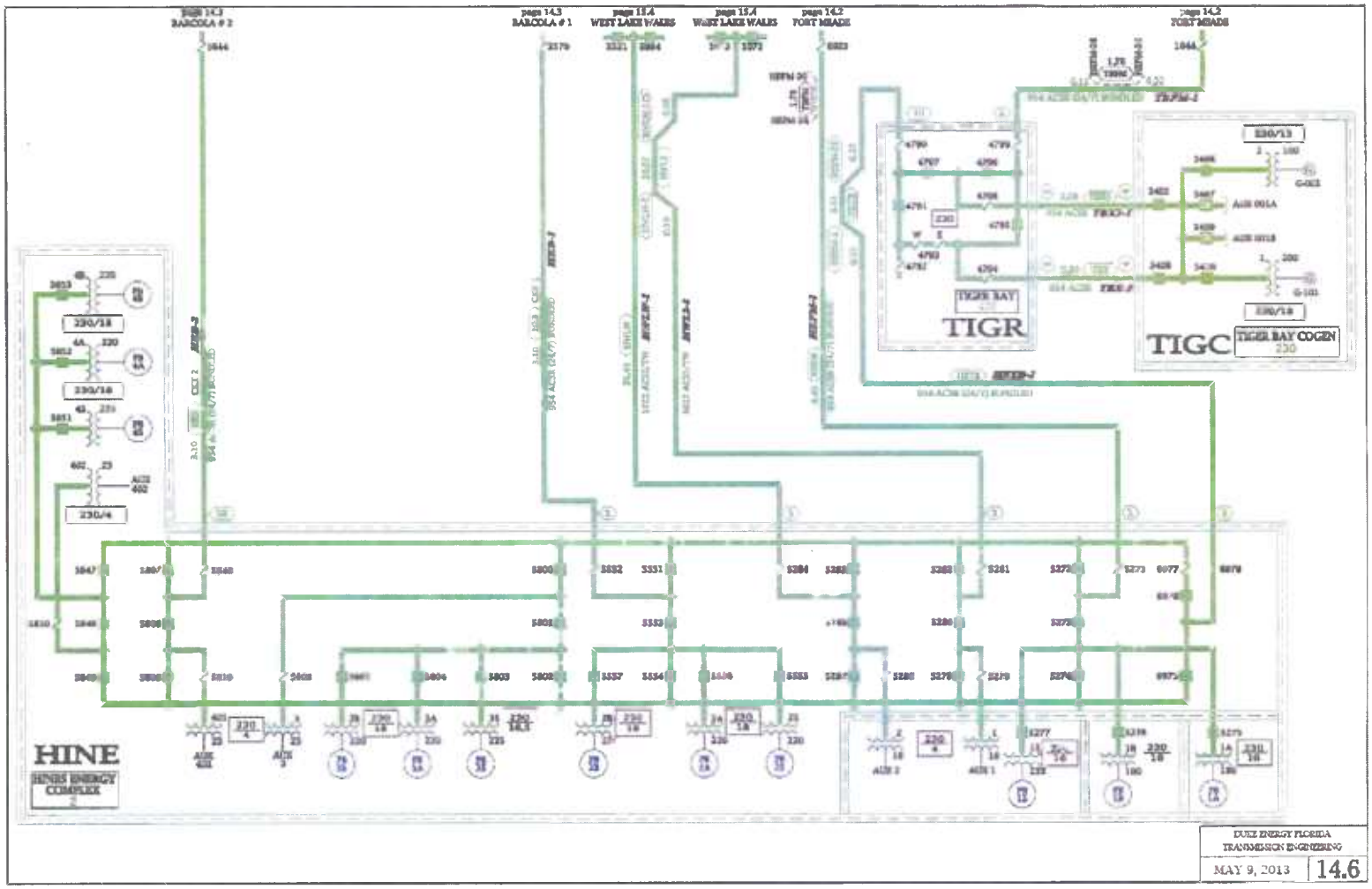
- No other options were considered reasonable or necessary.




from SOCO Twin Lakes & Dasher
to Madison To & Madison
from SOCO Pine Grove & TECO
to West Lake & Suwannee Steam
to West Lake & Burnahm & Jasper
CR10 / SR 90
Suwannee Steam Generators (qty 3)
existing Suwannee Peakers (qty 3)
to Lovell To & Fort White 115
to Suwannee Plant
to Occident
Swift Creek 1
new 230kV CT
new 115kV CT
River Rd
to Perry
to Fort White 230
to FPC 230 and Live Oak

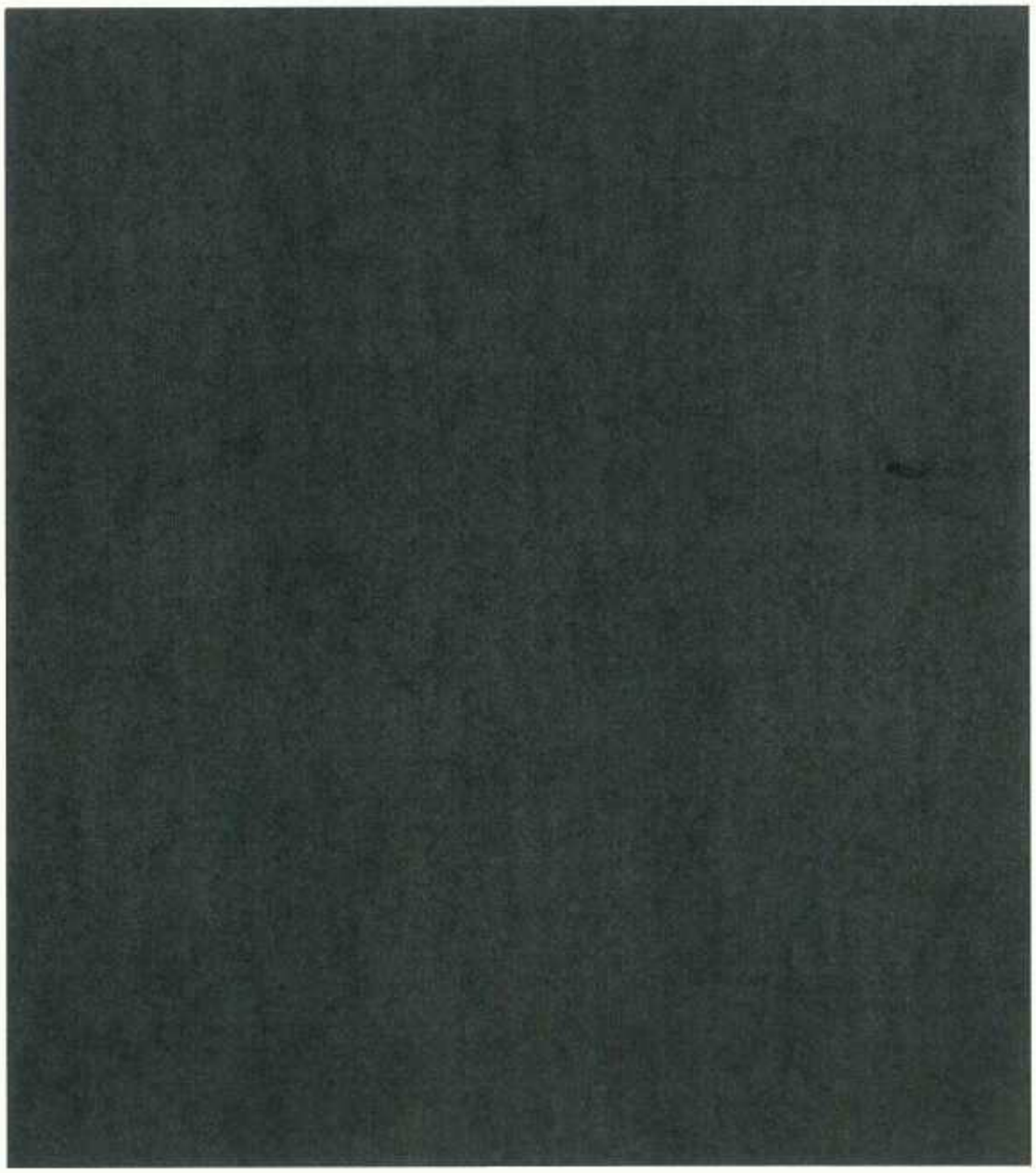
Docket No. _____
Duke Energy Florida
Exhibit No. ___ (ES-2)
Page 1 of 1

Existing HEC Combined Cycle Power Plant Blocks and the Existing Transmission Interconnections



REDACTED

Potential Generation Facility Acquisitions Evaluated for Transmission Cost Impacts to the DEF transmission system



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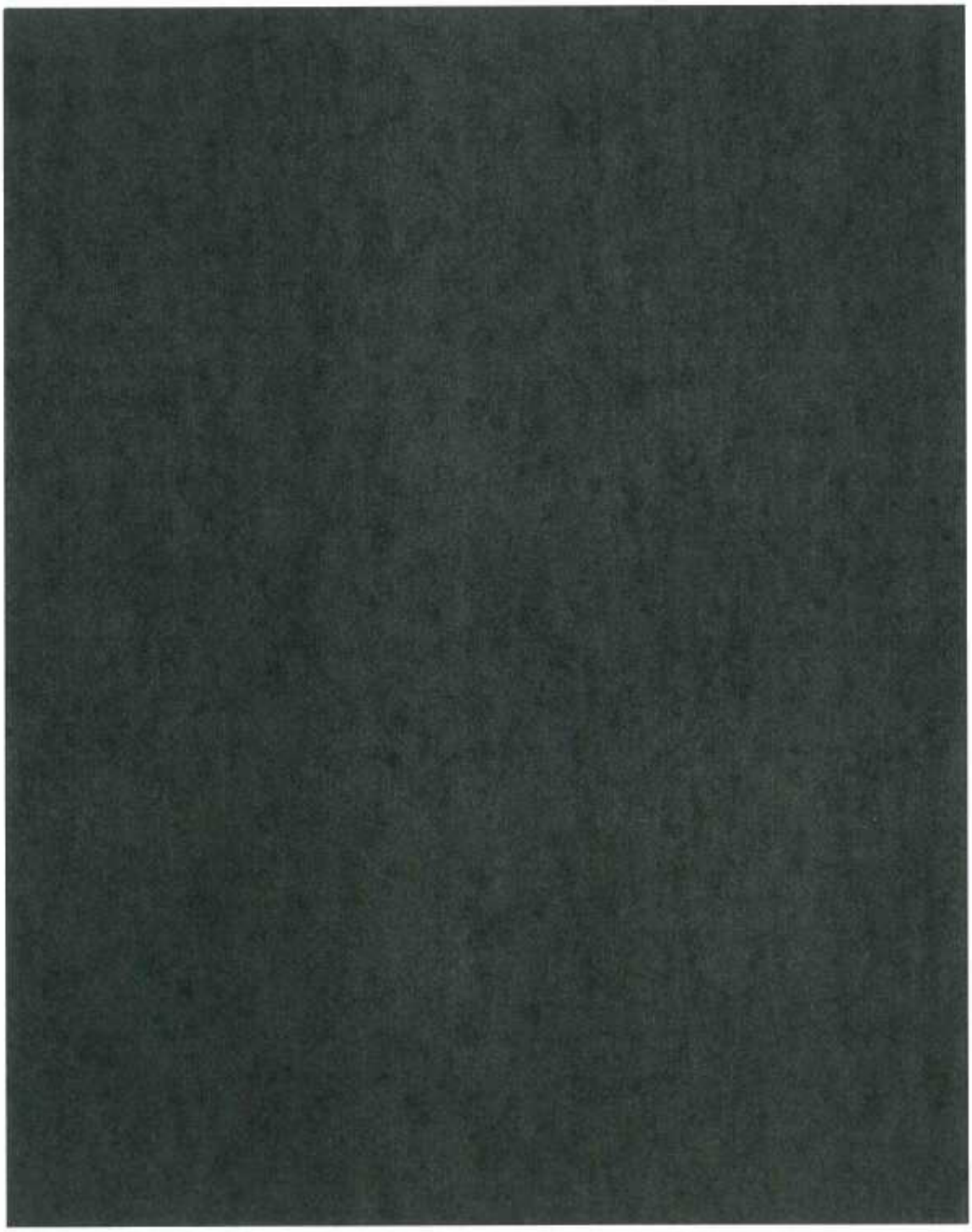

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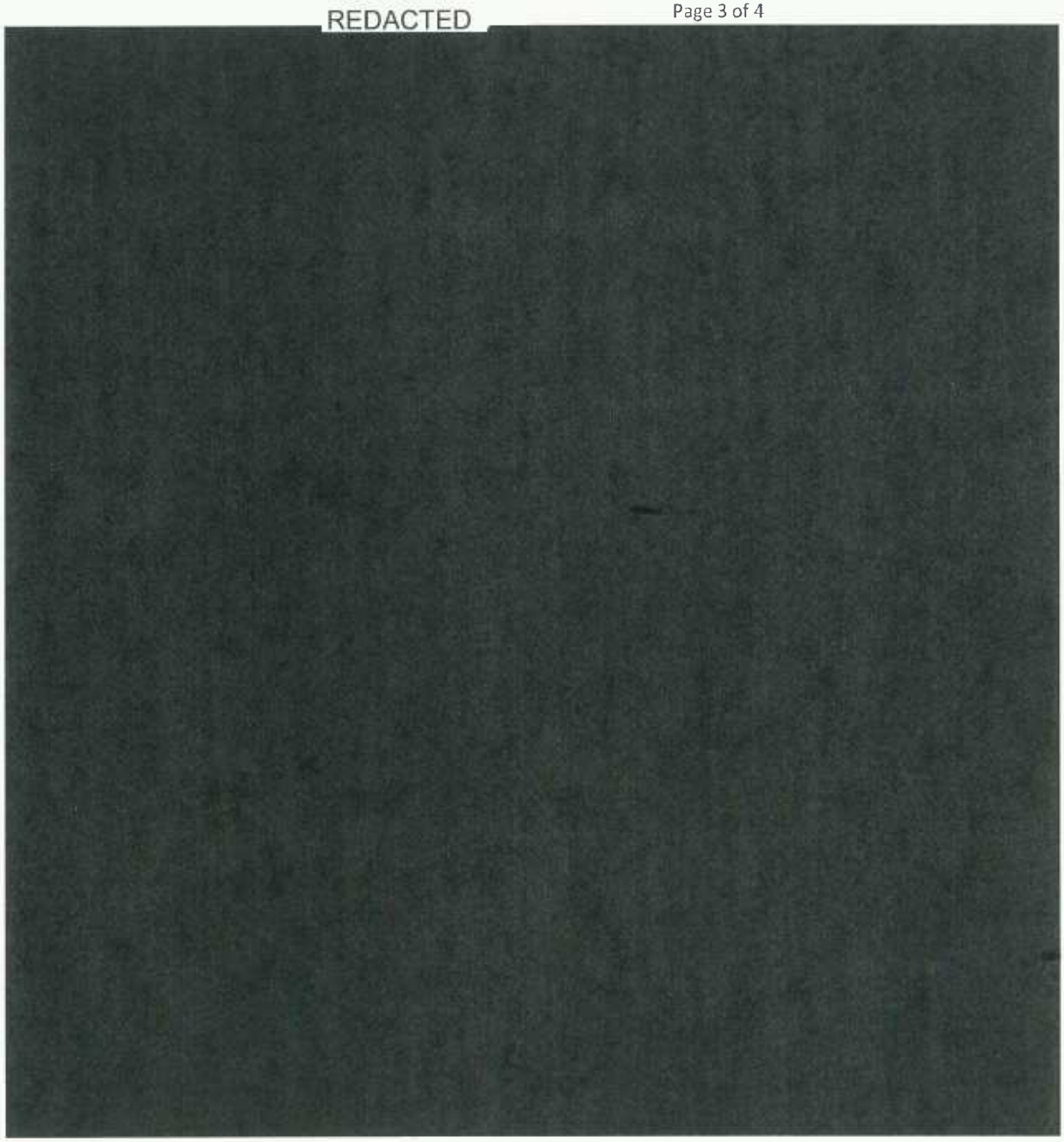

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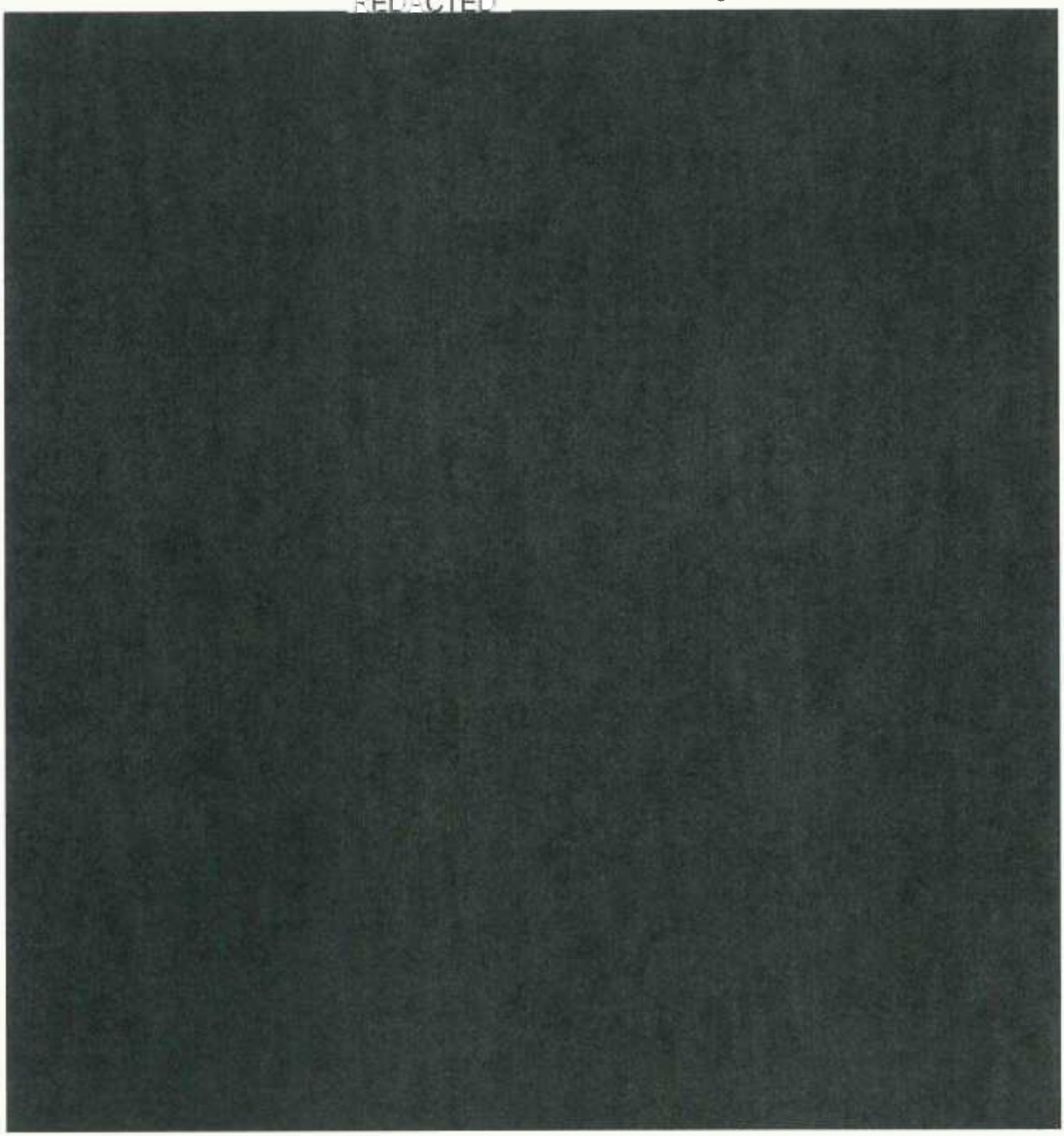

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. _____ Submitted for filing: May 27, 2014

DIRECT TESTIMONY OF KEVIN DELEHANTY

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 7
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Kevin E. Delehanty KED-1

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

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. _____

DIRECT TESTIMONY OF KEVIN DELEHANTY

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Kevin Delehanty and I am employed by Duke Energy Business Services LLC, the service company affiliate of Duke Energy Florida, Inc. ("DEF" or the "Company"). My business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director of Market Fundamentals. In this role, I am responsible for preparation of the Fundamental Forecast, which is the Duke Energy Corporation ("Duke Energy") long-term fossil fuels commodity price forecast for all the subsidiary electric utilities, including DEF. As a result, I am responsible for providing the long term commodity price component of the fuels forecast to DEF for its Integrated Resource Planning ("IRP") process.

Q. Please summarize your educational background and employment experience.

A. I received an Associate's degree in Industrial Electronics from Spartanburg Technical College in May, 1982. In May 1990, I received a Bachelor of Science degree in Electrical Engineering from the University of South Carolina – Columbia. I have also been a licensed Professional Engineer in the State of South Carolina since 1994.

I joined Duke Power Company in June, 1982 as an Engineering Associate in the Distribution Engineering Group. From 1982 – 1987, I was a Power Quality Engineer in the Electrical System Design Group. I joined the System Planning Group in 1990 where I was responsible for production cost modeling, project evaluation, and financial analysis. Over the next ten years I served in a variety of roles leading cross functional teams in planning and asset strategy. In 2000, I joined the Bulk Power Marketing Group as a Senior Structured Planning Engineer responsible for valuation and risk analysis of large structured power deals. In 2005, I joined the Corporate Strategy Group as Manager of Commodity Price Fundamentals responsible for supervision of the commodity price forecasting process using external consultants for modeling and data. Following the merger with Cinergy in 2006, I was named Director of Market Fundamentals and Competitive Analytics responsible for the development of the long term fuel price outlooks used in all long term planning studies.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of DEF in support of its Petition for Determination of Cost Effective Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc. for the Suwannee Simple Cycle project and the Hines Chillers Power Uprate project. I will describe the process for developing the Fundamental Forecast and explain why the Fundamental Forecast is a reasonable long-term fuels price forecast for the Company to use in its IRP process.

Q. Are you sponsoring any exhibits to your testimony?

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

- Exhibit No. ___ (KD-1), a chart of the Company's base, high, and low natural gas price forecast;
- Exhibit No. ____ (KD-2), a chart of the Company's base natural gas price forecast and other industry natural gas price forecasts;
- Exhibit No. ___ (KD-3), United States Energy Information Administration ("EIA") Map of major North American shale basins; and
- Exhibit No. ___ (KD-4), United States Potential Gas Committee chart of Total Potential Resources.

The Company generated exhibits identified above were prepared under my direction and control, and each is true and accurate. The other exhibits were prepared by government agencies charged with collecting, collating, and publishing information of the type included in the identified exhibits, they are

reliable industry resources for this information, and this information is typically used by the Company as resource material in the preparation of the Fundamental Forecast.

Q. Please summarize your testimony.

A. The Fundamental Forecast is Duke Energy's long-term fuels forecast. It is a fundamentals-based forecast reflecting Duke Energy's long-term outlook for resource planning purposes and other long-term investment decisions. The Fundamental Forecast is based on an extensive review and a rigorous analysis of available and relevant information that affects fuel commodity prices. It reflects industry expertise and Duke Energy's expertise and professional judgment of future fuel costs. It is further in line with other contemporary, industry fuels forecasts. The Fundamental Forecast, therefore, reasonably represents future fuel commodity prices.

Natural gas is the fuel planned for the Suwannee Simple Cycle project and the fuel currently serving the Hines combined cycle power plant units where the Hines Chillers Power Uprate project will be installed. It is a readily available fuel source, given current and projected levels of long-term supply of natural gas. The increase in the available gas supply and production from conventional and, in particular, unconventional tight gas and shale rock formations in the United States due to improvements in drilling and well stimulation technologies is expected to continue to favorably impact fuel prices. Natural gas is available in sufficiently

abundant supply that natural gas is a relatively economic fuel choice for power generation well into the future.

III. DEF'S FUELS PRICE FORECAST.

Q. Does DEF have a fuels forecast?

A. Yes. DEF has both a short-term fuels forecast and a long-term forecast. The short-term fuels forecast is based on observed market prices and is used mainly for operational purposes. The long-term forecast is a fundamentals-based forecast and it reflects Duke Energy's long-term outlook for resource planning purposes and other long-term investment decisions for Duke Energy and all of its electric utilities, including DEF. All of the long-term fundamental commodity prices are developed within the context of a comprehensive, internally consistent modeling process. The short term fuel forecast is based on available futures market prices, spot market prices, and short-term contract prices for the fuels used by the electric utilities. The short term natural gas fuels price forecast, for example, is based on the New York Mercantile Exchange ("NYMEX") futures contract prices for United States natural gas. The NYMEX natural gas futures market is an electric utility industry standard index of future market prices for United States natural gas. The Company transitions from its reliance on the short term fuels forecast to the Duke Energy Fundamental Forecast, or long term fuels forecast, for the long term investment decisions, such as building and operating new power plants, in its IRP process.

Q. Why does Duke Energy prepare a Fundamental Forecast?

A. The Fundamental Forecast is an integral part of Duke Energy's long term planning processes, in particular, its resource planning. Relevant short- and long-term fuel commodity prices and their differentials over time are important economic factors in determining the types and timing of new generation additions to DEF's system. Fuel commodity prices are also relevant to the determination of the most efficient method of operating existing and proposed generation plants on DEF's system in compliance with system operational and environmental requirements. Duke Energy utilizes published market prices for the portion of the forecast curve where the relevant fuels are actively traded, as well as other market intelligence like competitive bids received in the fuel procurement process, and then relies on market fundamentals to fill out the balance of the forecast. Futures market prices are illiquid after the first few years and often do not reflect the impacts of proposed environmental rulemaking, retirements of existing generation, or changes in technology. A Fundamental Forecast is a forward-looking evaluation of the marginal cost of supply at the expected level of demand. Iterative modeling simulations are performed using detailed supply and demand curves for each commodity until the energy markets come into balance, producing an internally consistent set of future market prices. The modeling process utilizes a combination of historical industry data coupled with assumptions which help define the future market environment. The fundamental forecasting process provides a detailed narrative of where the future energy supplies and corresponding demand will come from and it will help identify the key variables.

Although some of these input assumptions may prove to be incorrect in the future, the process itself still yields important information as to their cause and effect. The real strength of the fundamental forecasting process lies in the fact that it is a methodical, analytical process, repeated at regular intervals, and it is continuously refined. The Fundamental Forecasting process, which allows Duke Energy to evaluate the impact of the changing energy landscape on future commodity fuel prices, is essential to DEF's IRP process.

Q. How does Duke Energy prepare its Fundamental Forecast?

A. Duke Energy starts its Fundamental Forecast with the assistance of an expert energy consultancy in the field of fuels forecasting in the industry. Duke Energy's current industry consultant is Energy Ventures Analysis, Inc. ("EVA"). EVA was selected from five industry energy consultant responses to a request for proposal ("RFP") in July 2012. EVA was selected based on, among other factors, its experience, modeling processes and tools, market and regulatory expertise. EVA was selected by an internal team of experts from different Duke Energy departments, including Fuel Procurement, Load & Fundamental Forecasting; Strategic Engineering and Environmental Policy; and Integrated Resource Planning. EVA is an industry expert in fuel price forecast modeling and analysis.

Duke Energy relies on EVA to employ its industry leading modeling processes and databases to develop a long-term energy commodity price forecast that EVA provides Duke Energy. Duke Energy subject matter experts review the EVA assumptions and data inputs in the long-term energy commodity price

forecast for consistency with Duke Energy's own internal planning assumptions and data inputs. Duke Energy works in a collaborative manner with EVA to discuss the input assumptions, model results, and corresponding conclusions in the EVA reference case. Following this review, Duke develops a list of input assumption changes to be considered for the next iteration of the Duke reference case and then works with EVA to facilitate the changes within the constraints of the modeling process. This process continues until both Duke Energy and EVA are satisfied that the data inputs and assumptions in the long-term commodity price forecast are credible and that the results of modeling the assumptions in the forecast are valid. Further, validation of the modeling assumptions and results is obtained from reviews by various internal planning groups until Duke Energy is comfortable with the credibility of the long-term energy commodity price forecast.

Duke Energy has employed this process since 2005 and has worked with leading energy consultants like Wood Mackenzie, CERA, ICF, Global Energy/Ventyx, and EVA. The Fundamental Forecast is released each spring with an updated forecast typically in the fall of the year, if required by material changes in the underlying assumptions in the Fundamental Forecast. The preparation of the Fundamental Forecast, however, is a continual process in the sense that Duke Energy routinely monitors and updates, when necessary, the assumptions underlying the Fundamental Forecast based on changes in the market and evolving conditions in the national and regional economies where the electric utilities are located, political and regulatory conditions, environmental conditions

and other factors that have or may have an impact on the Fundamental Forecast.

Q. What types of changes are made by Duke Energy to the EVA Fundamental Forecast assumptions?

A. Duke Energy typically makes changes only to assumptions regarding data inputs in technical areas where Duke Energy possesses specialized expertise or to assumptions regarding future policy directives where Duke Energy believes it has more complete or relevant information. For example, in the 2013 Fundamental Forecast, Duke Energy adjusted state level electric sales growth rates and raised the penetration level assumptions of certain renewable resources in select states where Duke Energy electric utilities operate. Duke Energy also modified coal plant retirement assumptions for existing coal plants, capital and operation and maintenance ("O&M") cost assumptions for new generation resources with which Duke Energy has construction and operation experience, and assumed remedies for future 316(b) water regulations, all based on its internal information and expertise. These assumptions changes are typically few in number; the overwhelming majority of the assumptions in the Fundamental Forecast were developed by EVA and retained by Duke Energy.

Q. Are there any other adjustments by Duke Energy to the EVA forecast in the Fundamental Forecast?

A. Yes. The EVA forecast did not include a national climate or carbon policy assumption in the EVA Fall 2012 base forecast, which was the starting point for

the development of the 2013 Duke Energy outlook, i.e. the Fundamental Forecast. EVA did follow up with a carbon scenario case of their own as part of their Fall 2013 Outlook. Duke Energy has included a price on carbon within its base fundamentals outlook since 2006 as a way of capturing the potential impact of uncertain future policy for regulating CO_2 emissions, and although current legislative efforts to enact a policy that places a national price on carbon remain highly uncertain, it is still a possibility. In the absence of legislation the United State Environmental Protection Agency ("EPA") is moving ahead with regulating CO_2 emissions from existing fossil fuel-fired power plants, and we expect a proposal from the EPA in June 2014. Therefore, Duke Energy believes it is prudent to model a price on carbon as a way of capturing the risk of potential, but uncertain future legislation and pending EPA regulation of CO_2, and the impact of carbon policy at the national level within the context of its fundamental fuel price outlook. The carbon price Duke Energy currently uses in its fundamentals forecast is a direct input to the process and has been set at a level we believe to be a reasonable trajectory to represent the risk of federal climate change legislation or regulation given the current uncertainty surrounding such policy. The carbon price trajectory used is also in our view reflective of the pricing that policy makers might consider acceptable if or when they act.

Because of the high degree of uncertainty surrounding the outcome of climate change policy, however, DEF, in its IRP process, runs scenarios off the Duke Energy fundamental forecast carbon price trajectory that include a no carbon cost forecast to produce a more robust analysis.

Q. How is the Fundamental Forecast used in the IRP process?

A. After the Fundamental Forecast is reviewed and validated as a credible long-term commodity price forecast, it is provided to Duke Energy's fuels procurement group where it is combined with other market data to develop the final fuel price inputs to the resource planning models. For the natural gas commodity component, the fuels procurement group utilizes futures market quotes from the NYMEX to price the first three years, followed by a two year transition period of blended prices to the long term fundamentals for the balance of the forecast. After establishing the commodity price curve, the procurement group develops plant specific fuel price inputs by factoring in existing contracts, as well as fixed and variable transportation costs. Exhibit No. ___ (KD-1) to my direct testimony is a chart of the fundamental natural gas forecast. Forecast scenarios based on the Fundamental Forecast are also developed. These include low and high natural gas forecast scenarios around the base natural gas price forecast in the Fundamental Forecast. See Exhibit No. ___ (KD-1).

Q. How were the low and high natural gas forecast scenarios developed in the Fundamental Forecast?

A. The low and high natural gas forecasts in the Fundamental Forecast are developed by comparing the Duke Energy base natural gas price forecast in the Fundamental Forecast to contemporary, well-recognized industry natural gas price forecasts and applying statistically relevant standard deviations to the data. This methodology produces the shaded areas around the Duke Energy Fundamental

Natural Gas Forecast shown in Exhibit No. __ (KD-1) and results in the calculation of the low and high natural gas price forecasts around the Fundamental Natural Gas Forecast. Based on these calculations, the low natural gas forecast is 18 percent lower and the high natural gas forecast is 14 percent higher than the Duke Energy Fundamental Natural Gas Forecast, as shown in Exhibit No. ___ (KD-1). Duke Energy's methodology reasonably anchors its low and high natural gas price scenarios to contemporary industry natural gas price forecasts and ensures that the range of potential natural gas prices in the Duke Energy Fundamental Natural Gas Forecast is not out of line with industry forecasts.

Q. In your opinion, is the Fundamental Forecast a reasonable view of future fuel commodity prices?

A. Yes. The Fundamental Forecast is based on an extensive review and a rigorous analysis of available and relevant information that affects fuel commodity prices. Duke Energy relies on industry expertise and its own expertise to develop this information in the Fundamental Forecast and it incorporates the best available data regarding these assumptions into the Forecast. The Fundamental Forecast reflects industry expertise and Duke Energy's best professional judgment of future costs at the time the Fundamental Forecast is prepared.

Duke Energy also vets this Forecast against other forecasts available in the industry, and Duke Energy-specific information regarding supply and demand, marginal costs, plant operational characteristics, and observable data regarding

commodity prices. As shown in Exhibit No. ___ (KD-2), and as I explained above with respect to the development of the low and high natural gas price scenarios, the Company's natural gas forecast is in line with other contemporary natural gas forecasts (both public and proprietary) prepared by leading industry consultants. As a result, the Fundamental Forecast reasonably represents future fuel commodity prices.

Q. Do you have an opinion regarding the use of natural gas as a fuel source for the Suwannee Simple Cycle power plant?

A. Yes. Natural gas is and will be a competitively-priced fuel source for the Suwannee Simple Cycle Power Plant. It is also the existing fuel for the Hines combined cycle power plant units where the Hines Chillers Power Uprate Project will be installed. Natural gas is an attractive economic fuel source for the generation of electricity for DEF's customers compared to the total cost of generation for other types of generation technologies. Natural gas is also an attractive fuel source because, compared to oil and coal, it is a cleaner burning fuel and does not have the same level of environmental costs and related impacts associated with generation plants using those alternative fuels. This results in a favorable impact on the relative capital cost of constructing generating facilities capable of complying with current and ever increasing environmental regulations. As a result, natural gas is the economic fuel of choice for electric generation for customers at this time.

Q. Why does the Company consider natural gas to be an economic long-term fuel source for electrical energy production?

A. In the last decade, advances in natural gas production technology have provided natural gas producers access to unconventional gas supplies that previously were not economic production resources. These unconventional gas supplies are in tight gas sandstone structures and shale rock formations deep below the ground where natural gas in an abundant quantity is trapped within the rock. Improvements in drilling and well stimulation technologies now provide an economic method to drill and hydraulically fracture the rock and capture the large quantities of natural gas trapped in these impermeable rock formations. This advanced drilling technology is colloquially referred to as "fracking," because the shale rock formations that trap the natural gas are fractured by high pressure water injected into the rock formations during the well completion process. Vast shale rock formations or "shale plays" extend across the United States and Canada. Exhibit No. ___ (KD-3) to my direct testimony is a map of the North American shale plays. This map from the EIA shows the current and prospective shale plays in addition to the natural gas basins. As the map makes clear, there are abundant shale plays in North America, providing a long-term source of supply of natural gas for natural gas users in the United States.

The ultimate size of the United States natural gas resource base has been estimated at 2,384 trillion cubic feet, as shown in Exhibit No. ___ (KD-4), according to the latest report from the United States Potential Gas Committee 2013 Report from the United States Potential Gas Committee at the Colorado

School of Mines. This estimate represents a 25% increase from their previous report in 2011 and at the current rate of United States consumption of approximately twenty five trillion cubic feet per year, the United States has ample domestic reserves.

As a result of the new drilling and completion technologies there has been a tremendous increase in United States unconventional gas production over the last five years. In the last five years the marketed production of United States natural gas has increased by 21% according to the EIA. But an even more impressive statistic is the percentage of natural gas production from shale resources which has increased from about 11% of the national total in 2008 to over 35% by the end of 2012.

Shale resources are increasingly displacing conventional sources of gas in the Gulf of Mexico and elsewhere, and that has further implications on the reliability of supply. By moving on shore, producers are reducing the time it takes to bring new wells on line and those wells are less prone to disruption from hurricanes. The United States gas market is still subject to market volatility, in part due to the nature of the business where supply and demand must balance in real time and storage is finite and limited to certain regions by geology. However, short term price volatility arising from operational imbalances are not a significant threat to the value proposition of a natural gas combined cycle unit, the way long term fuel availability and price uncertainty is. The dramatic increase in the size of the gas resource base coupled with the speed at which it can be put in production has significantly improved the long term availability of natural gas and

immensely improved the value proposition of natural gas as a fuel source for electric generation.

The United States power market will also benefit greatly from the distributed nature of the shale reserves being located much closer to major demand centers like the Northeast. The development of the Marcellus and Utica shale basins has freed up pipeline capacity across the Southeastern United States, which has lowered basis differentials, i.e., the variation in price based on constraints at the gas hub delivery location, and will also benefit future gas consumers in Florida in reduced transportation costs. This increase in the available gas supply and production of natural gas is expected to continue to favorably impact fuel prices with natural gas price projections being relatively economic to other fuels for energy production well into the future.

Q. If low-cost natural gas is abundant will that increase the generation of energy from natural gas in the United States?

A. Yes. Natural gas is the predominant fuel source for new electric power generation in the United States, and natural gas-fired generation has displaced a significant portion of the existing coal-fired generation fleet, because of the relatively low cost of natural gas and the increasing cost of coal-fired generation due to the compliance with increasing environmental regulations. There is also projected to be a sizable increase in industrial demand for gas as well as a significant increase in both pipeline and LNG exports due to the increased size of the resource base and the economic cost of production. This increase in demand is factored into our

Fundamental Forecast and, even with the projected increase in demand for natural gas, natural gas is still available in sufficiently abundant supply to render natural gas a relatively economic fuel choice for power generation over the long term.

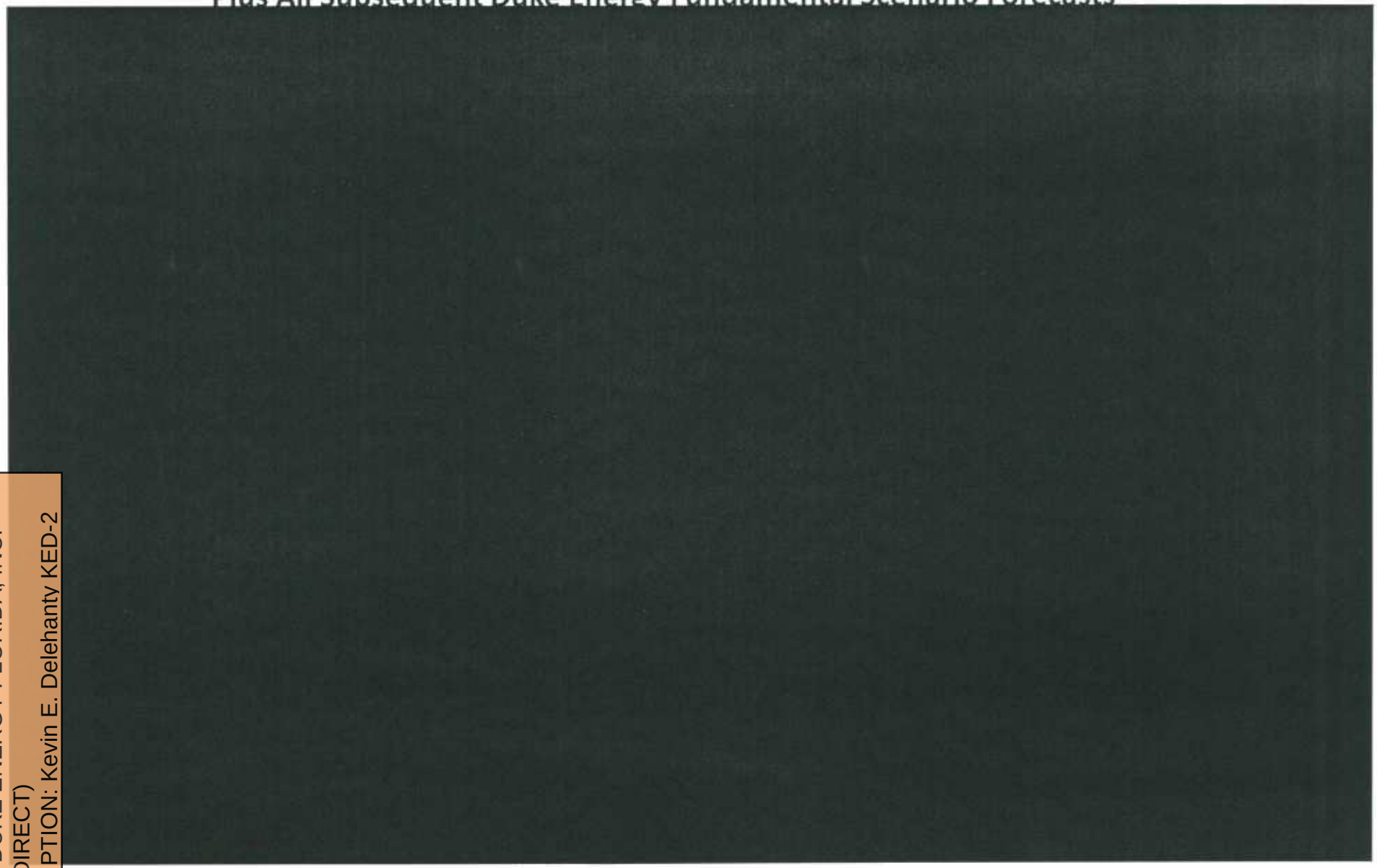
Q. Does this conclude your testimony?

A. Yes.

REDACTED

Fall 2013 Natural Gas Price Forecast Range at Henry Hub, LA

Plus All Subsequent Duke Energy Fundamental Scenario Forecasts

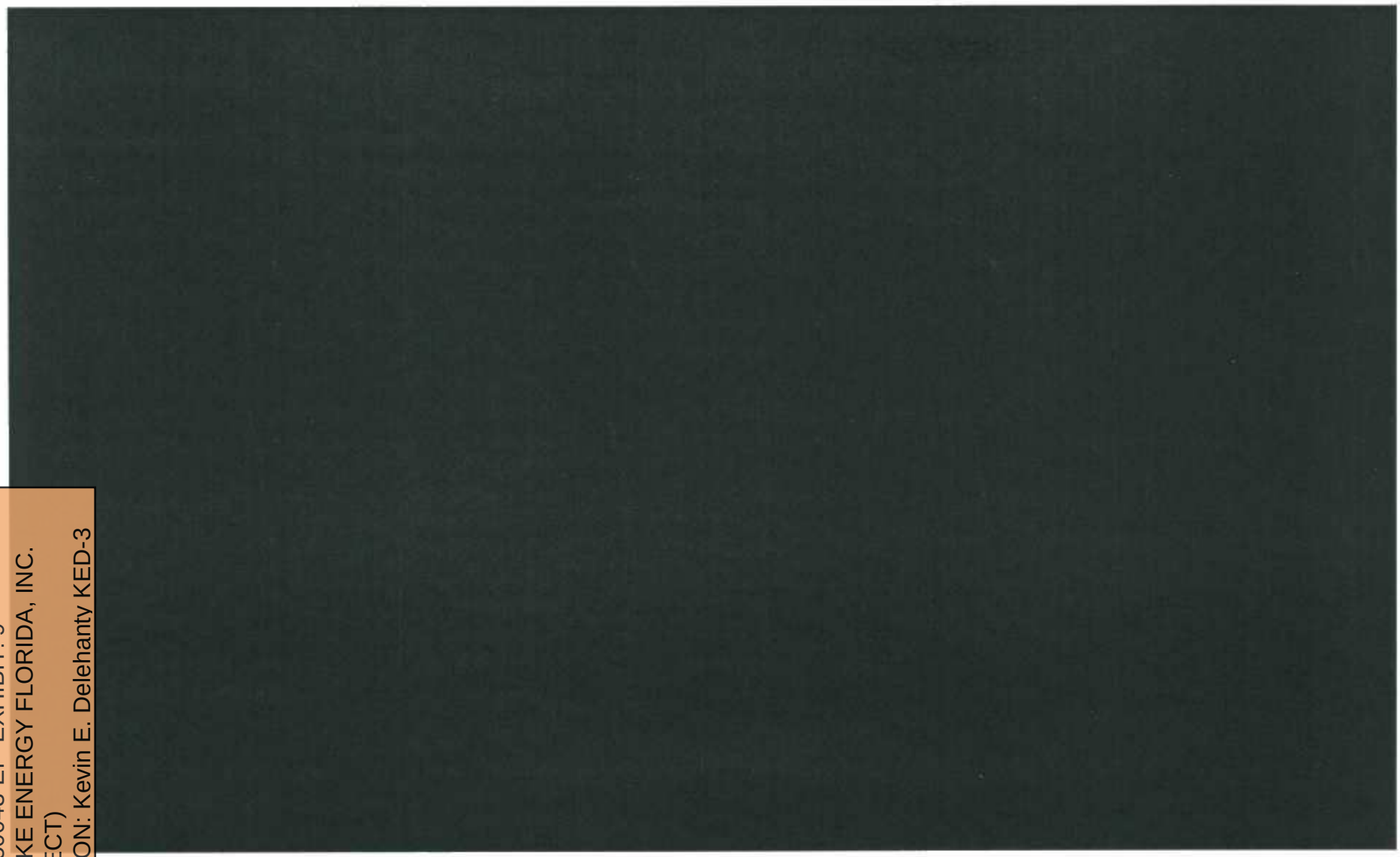


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 8
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Kevin E. Delehanty KED-2

DOCKET NO. _____
DUKE ENERGY FLORIDA
EXHIBIT NO. _____ (KED-3)
PAGE 1 of 1

REDACTED

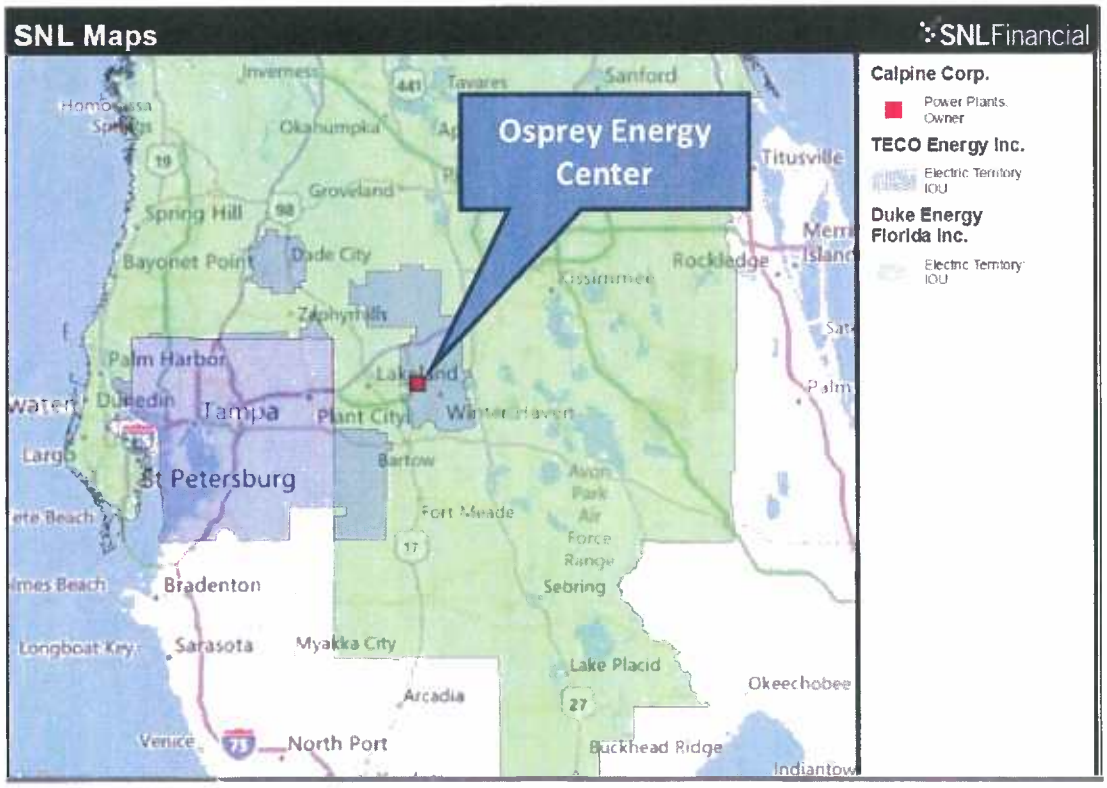
Duke Energy Fall 2013 Outlook for Natural Gas Prices at Henry Hub, LA



Fall 2013 Ext Range + 2014 upd

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Kevin E. Delehanty KED-3

DOCKET NO. _____
DUKE ENERGY FLORIDA
EXHIBIT NO. ____ (KGE-1)
PAGE 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 10
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Kris G. Edmondson KGE-1

Docket No. _____
Duke Energy Florida
Exhibit No. ____ (KGE-2)
Pages 1 through 84

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination that the Osprey Plant Acquisition and, alternatively, the Suwannee Simple Cycle Project is the most Cost Effective Generation Alternative to meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.

DOCKET NO. _____
Submitted for filing: January 30, 2015

EXHIBIT KGE-2 OF
DIRECT TESTIMONY
OF KRIS G. EDMONDSON
IS CONFIDENTIAL IN ITS ENTIRETY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 11
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Kris G. Edmondson KGE-2

REDACTED

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 12
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Kris G. Edmondson KGE-3

CALPINE CORPORATION

NYSE:CPN

Confidential

REDACTED

August 25, 2014

Att: John Burnett, Deputy General Counsel
Duke Energy Florida
299 First Avenue North
St. Petersburg, FL 33701
(727) 820-5184

Via e mail: John.Burnett@Duke.energy.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 13
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Matthew E. Palasek MEP-1

Re: Calpine Revised PPA and Acquisition Term Sheet

Dear Mr. Burnett,

In this Term Sheet, Calpine Corporation ("Calpine") is pleased to present a revised proposal for a Power Purchase Agreement ("PPA") and asset acquisition by Duke Energy Florida ("Duke") of the Osprey Energy Center ("Osprey" or "Osprey Facility"), a 599 MW natural gas-fired, combined-cycle generating facility located in Auburndale, Florida. We believe the proposed deal structure set forth below addresses both Duke's and Calpine's concerns that we have articulated and discussed, allows Duke to acquire Osprey at an attractive price, and protects Duke's customers from additional costs if the necessary regulatory approvals are not obtained in a timely fashion.

Deal Structure:

- 2 year PPA beginning January 1, 2015 followed by Duke acquisition of the facility in December 2016 (after FERC approval), or a 27-month PPA beginning October 1, 2014, with capacity payments adjusted to produce the same net present value of capacity payments under the 27-month PPA as under the 2-year PPA described in the attached Schedule A. The PPA will also include a one-time extension option, exercisable by Duke in its sole discretion, to extend the PPA term from January 1, 2017 through December 31, 2019,
- Duke will file for approval of the acquisition at FERC on a date that is mutually agreeable to Duke and Calpine, but no later than January 31, 2015. Duke will use its best efforts to aggressively and diligently pursue FERC approval, and Calpine and Duke will cooperate and coordinate fully with respect to Duke's efforts to obtain FERC approval.
- If approved by FERC, Duke agrees to acquire Osprey for $166 million (nominal dollars) at closing. At closing, Calpine will reimburse Duke for [redacted] in sunk costs associated with Duke's development efforts on the Suwannee Peakers Project. (Schedule B summarizes the key terms of the Osprey acquisition transaction.)
- If FERC rejects the acquisition, or [redacted], or fails to issue an order by [redacted], Calpine will pay Duke a one-time breakage fee of [redacted].
- [redacted]

** *Confidentiality. The consummation of any transaction is expressly conditioned upon the negotiation and execution of definitive agreements and the receipt of necessary corporate and regulatory approvals. This Term Sheet is being delivered to you on the understanding and on the condition that its existence and its content will be treated in a strictly confidential manner and will not be disclosed to any person or entity other than Duke and its advisors, unless such disclosure is otherwise mutually agreed to by Duke and Calpine. Specifically, neither this Term Sheet nor its contents may be referenced or introduced in any proceeding before the Florida Public Service Commission unless expressly agreed to in writing by Duke and Calpine.* **

- Calpine and Duke will share the actual costs of the FERC Section 203 filing equally.
- The definitive agreements will include terms and conditions that are standard for transactions of this type, including (without limitation) appropriate opportunities for Duke to perform a "walk-down" or "due diligence" inspection of the Osprey Facility before the definitive agreements are executed, and appropriate and satisfactory assurances to Duke that Calpine will properly maintain the Osprey Facility in accordance with good utility practice, and that Calpine will deliver the Osprey Facility to Duke in as good condition at closing as it is at the time of Duke's walk-down inspection. If the "walk-down" or "due diligence" inspection reveals a material adverse condition, i.e., a condition that would require material expenditures to remedy, then Calpine will either fix such condition, or Calpine may terminate negotiations without executing the definitive agreements contemplated hereby.
- Calpine's financial commitments (including, without limitation, Calpine's obligations to pay the breakage fee and to perform its obligations [redacted] will be backed by a parent guaranty of Calpine Corporation.
- Abeyance of Proceedings Regarding Suwannee Peakers Project: Upon acceptance of this Term Sheet by Duke and Calpine, Duke will file, and Calpine will support, a motion for abeyance or abatement of the proceedings in Florida PSC Docket No. 140111-EI as those proceedings relate to Duke's proposed Suwannee Peakers Project. The motion will include Duke's and Calpine's stipulation that their witnesses' testimony and exhibits may be entered into the record of PSC Docket No. 140111-EI and PSC Docket No. 140110-EI, but will request that any substantive hearings regarding the Suwannee Peakers Project in Docket No. 140111-EI be deferred to future dates, in order to provide Duke and Calpine the opportunity to complete the negotiation and execution of the definitive agreements contemplated in this Term Sheet.
- Exclusivity. For the period commencing on the date hereof and ending on the earlier of [redacted] the date of an adverse decision from FERC regarding the acquisition (i.e., either FERC rejection of the proposed acquisition, or FERC [redacted] (i) Calpine will not, and will cause its subsidiaries and its and their respective directors, officers, employees, agents and advisors (collectively, "Representatives") not to, take any action to, directly or indirectly, encourage, initiate, solicit, substantively respond to or engage in any discussions or negotiations with, or provide any information to, any entity or person other than Duke and its Representatives concerning any transaction similar to the transaction contemplated by this Term Sheet; and (ii) Duke agrees to work exclusively with Calpine to negotiate definitive documentation on the basis of this Term Sheet, and will not, and will cause its Representatives not to, during such period, engage in discussions or negotiations with any other entity or person in respect of the transaction contemplated by this Term Sheet, or any transaction similar to, or that would displace, the acquisition of the Osprey Facility contemplated by this Term Sheet.

The foregoing terms relating to confidentiality and exclusivity are binding as of the execution of this Term Sheet. The definitive transaction documents, if any, will include the specific numeric values regarding price for the Osprey Facility, reimbursement of certain costs to Duke, term and pricing under the PPA, and the breakage fee. Calpine is prepared to fully cooperate with Duke toward the expeditious completion of Duke's due diligence inspection of the Osprey Facility and the prompt negotiation of the definitive transaction agreements.

Best regards,

Todd Thornton
Senior Vice President, Calpine Corporation

Accepted for Duke Energy Florida by:

R. Alexander Glenn, President
Duke Energy Florida, Inc.

Schedule A

PPA Terms

Buyer:	Duke Energy Florida ("Duke")
Seller:	[TBD] ("Calpine")
Facility:	Osprey Energy Center ("Osprey" or the "Osprey Facility")
Product:	Capacity and Energy Tolling Agreement Duke would provide all fuel, including start and test fuel, to the Facility and Calpine will toll the fuel into energy at the rate requested by Duke.
Term:	January 1, 2015 – December 31, 2016 (or October 1, 2014 – December 31, 2016)*, plus a one-time extension option, exercisable by Duke in its sole discretion, to extend the PPA term through December 31, 2019, with Capacity Payments for the 2017-2019 Option Period as shown below.
Contract Capacity:	515 MW at Summer Reference Conditions
Energy Delivery Point:	249 MW delivered at Duke under Seller's firm transmission agreement described below. Remainder delivered at the Facility Bus-bar
Heat Rate:	[redacted] Btu/kWh at the Contract Capacity with a +/-2% dead-band Conditions
Capacity Payment:	$[redacted]/kW-month* 2015 $[redacted] kW-month* 2016
Option Period:	$[redacted] kW-month 2017 $[redacted]/kW-month 2018 $[redacted]/kW-month 2019
Variable O&M:	$[redacted] MWh for every MWh delivered in 2015$, escalating each contract year at GDP-IPD
Start Charges:	$[redacted] per combustion-turbine per start in 2015$, escalating each contract year at GDP-IPD
Gas Capacity Release:	Seller shall assign its firm gas transportation contract on Gulfstream to Buyer in the quantity of [redacted] MMBtu per day at a cost of $[redacted]/MMBtu per day.

* If Duke and Calpine agree to the initial PPA term being October 1, 2014 – December 31, 2016, the Capacity Payments for that term (i.e., through December 31, 2016) will be adjusted so that the Net Present Value of the Capacity Payments under the 27-month PPA is equal to the NPV of the Capacity Payments under the 24-month PPA set forth above, with discounting at Duke's current approved discount rate of 6.46%.

Availability Guarantee:	[redacted]% Summer (June – August) [redacted]% Winter (September – May) excluding planned maintenance outages and excused events. Failure to maintain this availability during any month will result in a Capacity Payment reduction of one percent (1%) for each percentage point the actual availability is below the Availability Guarantee.
Scheduling:	Duke will provide good-faith day-ahead forecast by 10:00 a.m. Eastern Prevailing Time on the business day prior to delivery. Schedule revisions will be accommodated on an intra-day basis provided the initial schedule revision is made four (4) hours prior to the start of any daily schedule. Schedule revisions made with less than a four (4) hour notice will be accommodated according to operating or permit constraints. Schedules will be limited to [redacted] per turbine per day for a minimum of [redacted] consecutive hours per turbine start with a minimum downtime of [redacted] hours.
Dispatch:	Duke will have the right to dispatch the Facility over its full range from minimum load to full output, within permit and technical limitations. The Facility will have Automatic Generator Control ("AGC") capability to allow Duke to dynamically control the output level.
Minimum Load:	[redacted]MW (in 1x1 operation), based on the physical limitations of the equipment, environmental permits, and ambient conditions.
Transmission:	Seller currently holds 249 MW of Firm point-to-point transmission from the Facility across TECO to Duke, with rollover rights. Per our discussions, at this time no additional transmission will be requested.
Environmental Change in Law:	Full pass through of all change in law costs

REDACTED

Schedule B

Asset Acquisition and Turbine Sale/Cancellation Provisions:

Buyer:	Duke Energy Florida ("Duke")
Seller:	[TBD] ("Calpine")
Facility:	Osprey Energy Center ("Osprey" or the "Osprey Facility")
Purchase Price:	$166,000,000 (sale of Osprey Facility either through the sale of assets comprising the facility or sale of 100% of the membership interest in Osprey Energy Center, LLC for a cash purchase on a debt-free, working capital-free, cash-free and capital spare parts-free basis)
Gas Capacity Release:	Seller shall assign its firm gas transportation contract on Gulfstream to Buyer in the quantity of [redacted] MMBtu per day (present rate is $[redacted]/MMBtu per day).
Transmission:	Seller currently holds 249 MW of Firm point-to-point transmission from the Facility across TECO to Duke, with rollover rights; Seller will assign its transmission contract and rights to Buyer.
Breakage Fee:	If FERC rejects the acquisition, or [redacted] Calpine will pay Duke a one-time breakage fee of $[redacted]
FERC Filing:	Duke will file for approval of the acquisition at FERC on or before January 31, 2015.
Transaction Close:	December 31, 2016
[redacted]:	[redacted]

FIRST AMENDMENT TO ASSET PURCHASE AND SALE AGREEMENT

THIS FIRST AMENDMENT TO ASSET PURCHASE AND SALE AGREEMENT (this "**Amendment**") is entered into this 29th day of January, 2015, by and between **DUKE ENERGY FLORIDA, INC.**, a Florida corporation ("**Purchaser**"), and **OSPREY ENERGY CENTER, LLC**, a Delaware limited liability company ("**Seller**").

WHEREAS, Purchaser and Seller entered into that certain Asset Purchase and Sale Agreement dated December 17, 2014 (the "**Asset Purchase and Sale Agreement**"), pursuant to which Seller has agreed to convey to Purchaser the Purchased Assets and Purchaser has agreed to assume from Seller, and covenant to pay, perform and discharge, the Assumed Liabilities (all capitalized terms used herein but not otherwise defined herein shall have the meanings ascribed to such terms in the Asset Purchase and Sale Agreement);

WHEREAS, the parties wish to amend the Asset Purchase and Sale Agreement and the schedules thereto.

NOW, THEREFORE, in consideration of the mutual promises and covenants contained herein and in the Asset Purchase and Sale Agreement, and for other good and valuable consideration, the receipt of which is hereby acknowledged, the parties hereto hereby agree as follows:

1. **Amendment to Article I of the Asset Purchase and Sale Agreement**. The parties wish to amend Article I of the Asset Purchase and Sale Agreement so that the reference to "Section 3.21(b)" in the definition of "APEC" is hereby deleted and replaced with a reference to "Section 3.20(b)".

2. **Amendments to the Asset Purchase and Sale Agreement**. The Asset Purchase and Sale Agreement is hereby amended as follows: (a) the reference to "January 30, 2015" in Section 5.04(b)(i) is hereby deleted and replaced with a reference to "March 9, 2015", (b) the reference to "Section 9.01(b)(v)" in Section 5.04(b)(i) is hereby deleted and replaced with a reference to "Section 9.01(b)(iv)", and (c) in the event that the Tolling Agreement has been extended beyond the Closing Date, the Tolling Agreement shall be deleted from Section 2.02(d) of the Seller Disclosure Schedules and, for purposes of clarity, shall be deemed a Purchased Contract.

3. **Counterparts; Facsimile Signatures**. This Amendment may be executed in more than one counterpart and may be executed by facsimile or other electronic signature and shall be binding upon the parties hereto and their respective successors, assigns, heirs, personal representatives and executors.

4. **Asset Purchase and Sale Agreement Confirmed**. Except as provided in this Amendment, the Asset Purchase and Sale Agreement is hereby confirmed and shall continue in full force and effect.

[Signatures appear on the following page.]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 14
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Matthew E. Palasek MEP-2

IN WITNESS WHEREOF, the parties have caused this Amendment to be executed as of the date first written above.

DUKE ENERGY FLORIDA, INC.

By: _____
Name: BRIAN D SAVOY
Title: SVP, CHIEF ACCT OFFICER + CONTROLLER

OSPREY ENERGY CENTER, LLC

By: _____ SVP
Name: W. Thaddeus Miller
Title: Chief Legal Officer

ASSET PURCHASE AND SALE AGREEMENT

by and between

DUKE ENERGY FLORIDA, INC.,

as Purchaser

and

OSPREY ENERGY CENTER, LLC,

as Seller

Dated as of
December 17, 2014

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ASSET PURCHASE AND SALE AGREEMENT

This ASSET PURCHASE AND SALE AGREEMENT is made as of December 17, 2014 (together with all annexes, schedules and exhibits attached hereto or delivered in connection herewith, this "Agreement") by and between Duke Energy Florida, Inc., a Florida corporation ("Purchaser"), and Osprey Energy Center, LLC, a Delaware limited liability company ("Seller" or "Company").

W I T N E S S E T H :

WHEREAS, Seller owns and operates a natural gas-fired combined-cycle generating facility in Auburndale, Florida (the "Project");

WHEREAS, Seller desires to sell, and Purchaser desires to purchase, all of Seller's right, title and interest in and to the Project and certain properties and assets associated therewith or ancillary thereto, on the terms and subject to the conditions set forth in this Agreement;

WHEREAS, concurrently herewith, Duke Energy Corporation, a Delaware corporation ("DEC"), has executed and delivered to Seller a guaranty, dated as of the date hereof, pursuant to which DEC has guaranteed the payment obligations of Purchaser hereunder (the "Parent Guaranty"); and

WHEREAS, concurrently herewith, Calpine Corporation, a Delaware corporation ("Calpine"), has executed and delivered to Purchaser a guaranty, dated as of the date hereof, pursuant to which Calpine Corporation has guaranteed the payment obligations of Seller hereunder (the "Calpine Guaranty").

WHEREAS, on December 5, 2014, [redacted]

NOW THEREFORE, in consideration of the mutual covenants and agreements set forth in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, Purchaser and Seller agree as follows:

ARTICLE I

DEFINITIONS

Section 1.01 Definitions. As used in this Agreement, the following defined terms have the meanings indicated below:

"Actions or Proceedings" means any action, arbitration, audit, hearing, investigation, litigation or suit (whether civil, commercial, labor, criminal, administrative, investigative or informal) commenced, brought, conducted, or heard by or before, or otherwise involving, any Governmental or Regulatory Authority or arbitrator.

"Affiliate" means, with respect to any Person, any other Person that directly, or indirectly through one or more intermediaries, controls, is controlled by or is under common control with the Person specified. For purposes of this definition, "control" of a Person means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person whether through ownership of voting securities or ownership interests, by Contract or otherwise, and specifically with respect to a corporation, partnership or limited liability company, means direct or indirect ownership of securities having the power to elect a majority of the board of directors or similar body governing the affairs of such Person.

"Agreement" has the meaning ascribed thereto in the preamble to this Agreement.

"Ancillary Agreements" means (i) the Bill of Sale, (ii) the Deed, (iii) the Assignment and Assumption Agreement, (iv) the Assignment and Assumption Agreement (CES), (v) the Parent Guaranty, (vi) the Calpine Guaranty, (vii) the Escrow Agreement, and (viii) any additional agreements, instruments of sale, transfer, conveyance, assignment and assumption or other documents that may be executed and delivered by any party hereto or any Affiliate thereof at or in connection with the Closing, if any.

"APEC" has the meaning ascribed thereto in Section 3.21(b).

"Apportioned Obligations" has the meaning ascribed thereto in Section 5.05(a).

[redacted]

"Assignment and Assumption Agreement" means the Assignment and Assumption Agreement, substantially in the form of Exhibit A-1, to be executed and delivered by Seller and Purchaser at the Closing.

"Assignment and Assumption Agreement (CES)" means the Assignment and Assumption Agreement, substantially in the form of Exhibit A-2, to be executed and delivered by Calpine Energy Services, L.P., a Delaware limited liability partnership, and Purchaser at the Closing.

"Assumed Liabilities" has the meaning ascribed thereto in Section 2.03.

"Base Purchase Price" has the meaning ascribed thereto in Section 2.06(a).

[redacted]

"Benefit Plan" means each employee benefit plan, within the meaning of Section 3(3) of ERISA, and each other plan, program, policy, agreement or arrangement relating to compensation, employee benefits (including fringe benefits), severance, employment, vacation, incentive compensation or bonus compensation, in each case that is sponsored, maintained or contributed to or required to be sponsored, maintained or contributed to by, or otherwise covering Seller or any of its Affiliates or the Operator or any of its Affiliates, or to which Seller or any of its Affiliates or the Operator or any of its Affiliates is a party, in each case for the benefit of any Facility Employee.

"Bill of Sale" means a Bill of Sale, substantially in the form of Exhibit B, to be executed and delivered by Seller at the Closing.

"Books and Records" means all files, documents, instruments, papers, books, reports, records, drawings, tapes, microfilms, photographs, letters, budgets, ledgers, journals, title policies, supplier lists, change order logs, regulatory filings, startup and commissioning documentation, vendor and OEM reports, operating data and plans, design and technical documentation (design specifications, functional requirements, operating instructions, logic manuals, flow charts, etc.), plant construction records (including asset and component purchase agreements), user documentation (installation guides, user manuals, training materials, release notes, working papers, etc.), critical infrastructure protocol (CIP) records and controls, internal and external correspondence, accounting records (excluding any general ledgers, accounts payable records or financial statements) and other documents primarily relating to the operation of the Project, and other similar materials that, in all such cases, are primarily related to the Project, the Project Site, the Purchased Assets or the Business in whatever form (including material electronic files), but excluding materials relating primarily to this transaction, market and similar forecast information and the Excluded Books and Records.

"Business" means the business, as currently conducted, of owning, operating and maintaining the Project, procuring fuel and generating, selling, transmitting and delivering electric energy from the Project.

"Business Day" means a day other than Saturday, Sunday or any day on which banks located in New York, New York are authorized or obligated to close.

"Calpine" has the meaning ascribed thereto in the recitals.

"Calpine Guaranty" has the meaning ascribed thereto in the recitals.

"Claim Amount" has the meaning ascribed thereto in Section 8.08(b).

"Claiming Party" has the meaning ascribed thereto in Section 8.05(b).

"Closing" has the meaning ascribed thereto in Section 2.05.

[redacted]

"Closing Date" means (a) January 3, 2017, or (b) such other date as Purchaser and Seller may mutually agree.

"Closing Payment" has the meaning ascribed thereto in Section 2.06(a).

"Code" means the Internal Revenue Code of 1986, as may be amended, modified, supplemented or replaced from time to time, and the rules and regulations promulgated thereunder.

"Company" has the meaning ascribed thereto in the preamble to this Agreement.

"Company Contracts" has the meaning ascribed thereto in Section 3.13(a).

"Confidentiality Agreement" means that certain Confidentiality Agreement, dated October 11, 2013, by and between Calpine and DEC.

"Contract" means any contract, agreement, lease, license, evidence of Indebtedness, mortgage, indenture, security agreement or other legally binding arrangement (whether oral or written and whether express or implied).

"Controlled Group Liability" means any and all liabilities (i) under Title IV of ERISA, (ii) under Section 302, 303 or 4068(a) of ERISA, (iii) under Section 412, 430 or 4971 of the Code or (iv) for violation of the continuation coverage requirements of Sections 601 et seq. of ERISA and Section 4980B of the Code or the group health requirements of Sections 701 et seq. of ERISA and Sections 9801 et seq. of the Code, in the case of each of the foregoing clauses (i) through (iv), with respect to any ERISA Affiliate.

"Credit Support Obligations" has the meaning ascribed thereto in Section 5.10(a).

"DEC" has the meaning ascribed thereto in the recitals.

"Deductible Amount" has the meaning ascribed thereto in Section 8.02(b).

"Deed" means the Special Warranty Deed, substantially in the form of Exhibit C, to be executed and delivered by Seller at the Closing.

"DOJ" has the meaning ascribed thereto in Section 5.04(b).

"Effective Date" means the date set forth in the first paragraph of this Agreement.

"Emission Allowances" means all environmental credits, offsets and allowances issued under the federal Clean Air Act (42 U.S.C. § 7401 et seq.), any applicable emission budget programs, or any other state, regional or federal emission trading program.

"Environmental Auditor" has the meaning ascribed thereto in Section 5.01.

"Environmental Claim" means any actual or threatened in writing Action or Proceeding, Order, directive, citation, demand, request for information, Lien which is not a Permitted Lien, notice of Liability or notice of regulatory requirement made, presented, sought or alleged by any Person and that (a) relates to or arises out of events, acts, omissions or conditions on or prior to the Closing, (b) relates to the Real Property, the Business, the Project Site or the Purchased Assets or the use, ownership or operation thereof, and (c) arises under or relates to any Environmental Law.

"Environmental Laws" means all applicable foreign, federal, state and local Laws, including rules of common law, and Orders with respect to pollution, preservation, or protection of the environment, natural resources or health and safety and shall include, without limitation, the Solid Waste Disposal Act, 42 U.S.C. § 6901 et seq.; the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. § 9601 et seq. ("CERCLA"), as amended by the Superfund Amendments and Reauthorization Act of 1986; The Resource Conservation and Recovery Act of 1976, 42 U.S.C. § 6901 et seq.; the Hazardous Materials Transportation Act, 49 U.S.C. § 1801 et seq.; the Clean Water Act, 33 U.S.C. § 1251 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. § 2601 et seq.; the Safe Drinking Water Act, 42 U.S.C. § 300f et seq.; the Oil Pollution Act of 1990, 33 U.S.C. § 2701 et seq.; The Occupational Safety and Health Act of 1970, 29 U.S.C. § 651 et seq.; and foreign, state and local analogs.

"Environmental Permits" has the meaning ascribed thereto in Section 3.17(b).

"ERISA" means the Employee Retirement Income Security Act of 1974, as may be amended, modified, supplemented or replaced from time to time.

"ERISA Affiliate" means any Person with whom the Company or the Operator is or was treated as a single employer under Section 414(b), (c), (m) or (o) of the Code.

"Escrow Agent" has the meaning ascribed thereto in Section 2.06(b).

"Escrow Agreement" means the Escrow Agreement, substantially in the form of Exhibit D, to be executed and delivered by Seller, Purchaser and Escrow Agent at Closing.

"Excluded Assets" has the meaning ascribed thereto in Section 2.02.

"Excluded Books and Records" has the meaning ascribed thereto in Section 2.02(e).

"Excluded Contracts" has the meaning ascribed thereto in Section 2.02(d).

"Excluded Governmental and Regulatory Approvals" has the meaning ascribed thereto in Section 2.02(i).

"Excluded Intellectual Property" has the meaning ascribed thereto in Section 2.02(j).

"Excluded Liabilities" has the meaning ascribed thereto in Section 2.04.

"Existing FPSC Docket" means FPSC Docket No. 140111-EI.

"Facility Employees" means the employees of the Operator or its Affiliates (including employees on vacation or leave of absence) who exclusively or primarily provide services to or for the Project, each of whom, as of the date hereof, is listed on Section 1.01(c) of the Seller Disclosure Schedule and which Schedule shall be updated on the last day of each calendar month by Seller prior to the Closing, and as of the Closing Date.

"FERC" means the Federal Energy Regulatory Commission.

"FERC Approval Order" means an Order issued by FERC under Section 203 of the Federal Power Act that approves the transactions contemplated hereby [redacted]

"FERC Mitigation Order" means an Order issued by FERC under Section 203 of the FPA that subjects approval of the transactions contemplated hereby [redacted]

"FPA" means the Federal Power Act.

"FPSC" means the Florida Public Service Commission.

"FRCC" means Florida Reliability Coordinating Council, Inc.

"Financial Statements" has the meaning ascribed thereto in Section 3.05.

"FTC" has the meaning ascribed thereto in Section 5.04(b).

"Fundamental Representations" has the meaning ascribed thereto in Section 8.01.

"GAAP" means generally accepted accounting principles in the United States, consistently applied throughout the specified period.

[redacted]

"Good Utility Practices" [redacted]

"Good Utility Practice"

"Governmental or Regulatory Approval" means any authorization, consent, approval, ruling, tariff, rate, certification, waiver, exemption, filing, variance, Permit or Order of, or any notice to or registration by or with, any Governmental or Regulatory Authority.

"Governmental or Regulatory Authority" means any federal, state, local or foreign government or subdivision thereof or any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government, including any governmental authority, agency, department, board, commission or instrumentality of the United States, including FERC, the Federal Communications Commission, the North American Electric Reliability Corporation and any of its regional entities, FRCC, FPSC, NERC, any state of the United States or any political subdivision thereof, and any tribunal, court or arbitrator(s) of competent jurisdiction.

"Hazardous Substance" means any: (a) petrochemical or petroleum products, oil, coal ash, fly ash or bottom ash, coal combustion byproducts, pesticides, insecticides, fungicides, rodenticides, radioactive materials, radon gas, asbestos or asbestos-containing material, polychlorinated biphenyls, lead-based paint, urea formaldehyde foam insulation flammable or explosive materials, mold, biohazardous materials or waste, natural or synthetic gas, or silica; (b) chemicals, materials, substances, wastes, compounds, mixtures or by-products, whether solid, liquid or gaseous, that are identified, listed, defined, designated, restricted, prohibited or otherwise regulated as or included in the definition of "hazardous substances," "hazardous materials," "hazardous constituents," "hazardous wastes," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "regulated substances," "solid waste," "sludge," "toxic pollutants," "toxic air pollutants," "restricted hazardous materials," "extremely hazardous substances," "hazardous air pollutants," "dangerous or toxic substances," "chemical wastes," "special wastes," "pollutants," "contaminants" or words of similar meaning and regulatory effect under any Environmental Law; and (c) other chemicals, materials, substances, wastes, compounds, mixtures or by-products (in each case, whether solid, liquid or gaseous), the exposure to, or treatment, storage, transportation, disposal or release, of which is prohibited, limited or regulated by any Environmental Law.

"Hired Employee" has the meaning ascribed thereto in Section 5.07(b).

"HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as may be amended, modified, supplemented or replaced from time to time, and the rules and regulations promulgated thereunder.

"Indebtedness" of any Person means, without duplication, any and all liabilities and obligations of such Person (a) for borrowed money or indebtedness issued or incurred in

substitution or exchange for indebtedness for borrowed money, (b) evidenced by notes, bonds, debentures, mortgages or other debt instruments, debt securities or other similar instruments, (c) under capital leases or similar arrangements, and (d) in the nature of guarantees of the obligations described in clauses (a) through (c) above of any other Person or that is recourse to such Person or any of its assets.

"Indemnification Letter of Credit" has the meaning ascribed thereto in Section 8.09.

"Indemnification LOC Issuing Bank" has the meaning ascribed thereto in Section 8.09.

"Indemnity Escrow Account" has the meaning ascribed thereto in Section 2.06(b).

"Indemnity Escrow Amount" has the meaning ascribed thereto in Section 2.06(a).

"Indemnity Escrow Fund" has the meaning ascribed thereto in Section 2.06(a).

"Indemnity Escrow Period" has the meaning ascribed thereto in Section 2.06(b).

[redacted]

"Initial HSR" has the meaning ascribed thereto in Section 5.04(b).

"Intellectual Property" has the meaning ascribed thereto in Section 3.12.

"Inventory" means any and all of the inventory items used for the Business including: capital spare parts, consumables; lubricants, chemicals, fluids, lubricating oils, filters, fittings, connectors, seals, gaskets, hardware, wire and other similar materials; maintenance, shop and office supplies; and tools (excluding any specialty tooling) or similar equipment; and similar items of moveable property located or held for use at the Project Site.

"Knowledge of Purchaser" means the knowledge of those Persons listed in Section 1.01(a) of the Purchaser Disclosure Schedule, in each case after reasonable inquiry.

"Knowledge of Seller" means the knowledge of those Persons listed in Section 1.01(b) of the Seller Disclosure Schedule, in each case after reasonable inquiry.

"Laws" means all laws, statutes, rules, regulations, ordinances, constitutions, codes, and other pronouncements having the effect of law of the United States or any state, county, city or other political subdivision thereof or of any Governmental or Regulatory Authority.

"Liabilities" means all Indebtedness, obligations, claims, costs, charges and other liabilities of a Person (whether absolute, accrued, contingent, determined, determinable, direct, fixed, indirect, matured or unmatured, or whether due or to become due), including those arising under any Law, Action or Proceeding or Order and those arising under any Contract or otherwise.

"Liens" means any mortgage, deed of trust, deed to secure debt, pledge, assessment, security interest, lease, lien, adverse claim, levy, charge, easement, restrictive covenant, option, right of way, encroachment, right of first refusal or other encumbrance, or any conditional sale contract, title retention contract or other contract to give any of the foregoing.

"LOC Fees" has the meaning ascribed thereto in Section 9.03(b).

"Loss" means any and all damages, fines, Taxes, penalties, deficiencies, losses and expenses (including without limitation interest, court costs, reasonable fees of attorneys, accountants and other experts), whether involving claims solely between the parties or by a third party against a party, and excluding any punitive, special, exemplary or remote damages (except for any such damages that are recovered by third-parties in connection with a Loss otherwise indemnified hereunder).

"Material Adverse Effect" [redacted] "Material Adverse Effect" [redacted]

[redacted]

[redacted]

"NERC" means the North American Electric Reliability Corporation.

"Operator" means Calpine Operating Services Company, Inc.

"Order" means any writ, judgment, order, decree, stipulation, determination, ruling, injunction or award issued, or otherwise put into effect by or under the authority of any court, administrative agency, or other Governmental or Regulatory Authority (in each such case whether preliminary or final) or any arbitrator.

"Other Losses" has the meaning ascribed thereto in Section 5.06(b).

"Overlap Period" means with respect to the Business, any taxable year or other period beginning on or before and ending after the Closing Date.

"Parent Guaranty" has the meaning ascribed thereto in the recitals.

"Permits" means all licenses, permits, certificates of authority, authorizations, approvals, registrations, franchises and similar authorizations granted by any Governmental or Regulatory Authority, including Permits required under Environmental Law.

"Permitted Liens" means (a) with respect to the Real Property: (i) any Lien for Taxes (x) which are not yet due and payable or (y) for the current year that are not yet delinquent or which are being contested in good faith, (ii) any statutory Lien or builders', mechanics', carriers', workers', warehousemens', repairers' and other similar liens and rights arising or incurred in the ordinary course of business for amounts not yet due or delinquent, (iii) all covenants, restrictions, conditions, easements, reservations, rights of way and other matters of record shown on the Title Commitment and all encumbrances and other matters disclosed on the Survey, (iv) zoning restrictions and other land use and environmental regulations by any Governmental or Regulatory Authorities as in effect on the date hereof, and any such restrictions and regulations not in effect on the date hereof which would not reasonably be expected to materially impair the value of the Property or the ability of Purchaser to use the Real Property in a manner consistent with Purchaser's intended use of the Project for the generation, sale, transmission, and delivery of electric power following the Closing, as the Project exists as of the Effective Date and (v) any imperfection of title or other similar Lien not in effect on the date hereof which individually or in the aggregate with other such Liens would not reasonably be expected to materially impair the value of the Property or the ability of Purchaser to use the Real Property in a manner consistent with Purchaser's intended use of the Project for the generation, sale, transmission, and delivery of electric power following the Closing, as the Project exists as of the Effective Date, and (vi) the Liens listed in Section 1.01(d)-1 of the Seller Disclosure Schedule, and (b) with respect to all Purchased Assets other than the Real Property: (i) any Lien for Taxes which are not yet due and payable or which are being contested in good faith, (ii) any statutory Lien or builders', mechanics', carriers', workers', warehousemens', repairers', and other similar liens and rights arising or incurred in the ordinary course of business for amounts not yet due or delinquent, (iii) any imperfection of title or similar Lien not in effect on the date hereof which individually or in the aggregate with other such Liens would not reasonably be expected to materially impair the

value of such asset or the ability of Purchaser to use such asset in a manner consistent with Purchaser's intended use of the Project for the generation, sale, transmission, and delivery of electric power following the Closing, as the Project exists as of the Effective Date, and (iv) the Liens listed in Section 1.01(d)-2 of the Seller Disclosure Schedule.

"Person" means any individual, corporation, company, voluntary association, partnership, joint venture, trust, limited liability company, other business or similar entity or Governmental or Regulatory Authority.

"Phase I Assessment" has the meaning ascribed thereto in Section 5.01.

"Post-Closing Tax Period" has the meaning ascribed thereto in Section 5.05(a).

"Pre-Closing Period" means all taxable years or other taxable periods that end on or before the Closing Date and, with respect to any Overlap Period, the portion of such Overlap Period ending on and including the Closing Date; provided that for purposes of this Agreement, anything occurring outside of the ordinary course of business on the Closing Date but after the Closing shall not be treated as occurring in a Pre-Closing Period.

"Project" has the meaning ascribed thereto in the recitals of this Agreement.

"Project Insurance Policies" has the meaning ascribed thereto in Section 3.16.

"Project Site" means the approximately 19.48 acre site upon which the Project is located in Polk County, Florida, as described in Section 3.10(a) of the Seller Disclosure Schedule.

"Project Software" means all Software that is used in the operation of the Business as presently conducted, or used in the operation, testing or maintenance of the Project.

[redacted]

"Property Reps" has the meaning ascribed thereto in Section 8.01.

"Purchase Price" means (i) the Base Purchase Price [redacted]

"Purchased Assets" has the meaning ascribed thereto in Section 2.01. "Purchased Contracts" has the meaning ascribed thereto in Section 2.01(d). "Purchaser" has the meaning ascribed thereto in the preamble to this Agreement.

"Purchaser Disclosure Schedule" has the meaning ascribed thereto in the introduction to Article IV.

[redacted]

"Purchaser Indemnified Parties" has the meaning ascribed thereto in Section 8.02(a)(i).

"Real Property" has the meaning ascribed thereto in Section 3.10.

"Representatives" means, as to any Person, its officers, directors, employees, agents, partners, members, stockholders, counsel, accountants, financial advisors, financing sources, engineers, consultants and other advisors.

"Responding Party" has the meaning ascribed thereto in Section 8.05(b).

"Retiree Benefits" has the meaning ascribed thereto in Section 3.15(e).

"Seller" has the meaning ascribed thereto in the preamble to this Agreement.

"Seller Disclosure Schedule" has the meaning ascribed thereto in the introduction to Article III of this Agreement.

"Seller Indemnified Parties" has the meaning ascribed thereto in Section 8.02(a)(ii).

"Seller's Marks" has the meaning ascribed thereto in Section 5.14.

[redacted]

"Separation Plan" has the meaning ascribed thereto in Section 5.02(c).

"Software" means any and all computer programs, whether in source code or object code, databases, username and passwords and change logs and access privilege logs, and all related documentation.

"Survey" means that certain survey prepared by Chastain Skillman Incorporated, dated May 4, 2009, under Drawing No. ESS-7287.19A.

"Tangible Personal Property" means all machinery, mobile or otherwise, equipment, vehicles, pumps, fittings, tools, plant monitoring, relaying, detection and control systems and annunciators, operator and other programming devices, subsystem control systems, programmable logic controllers, wired and wireless network systems, fixed and mobile plant interfaces and diagnostic systems, computer hardware, laptop computers, tablets, smart pads, mobile computing devices, furniture or furnishings, meter equipment and other tangible personal property (other than Inventory) owned or leased or purchased by the Company for use or consumption primarily at the Project.

"Tax" means any and all federal, state, provincial, local, foreign and other taxes, levies, fees, imposts, duties, and similar governmental charges (including any interest, fines, assessments, penalties or additions to tax imposed in connection therewith or with respect thereto, and whether payable directly or by withholding and whether or not requiring the filing of a Tax Return) including (a) taxes imposed on, or measured by, income, franchise, profits or gross

receipts, and (b) ad valorem, value added, capital gains, sales, goods and services, use, real or personal property, capital stock, license, branch, payroll, estimated withholding, employment, social security (or similar), unemployment, compensation, utility, severance, production, excise, stamp, occupation, premium, windfall profits, payment or fee in lieu of taxes (or any similar obligation), transfer and gains taxes, and customs duties.

"Tax Purchase Price" has the meaning ascribed thereto in Section 2.08.

"Tax Return" means any return, report, information return, declaration, claim for refund, election, disclosure, estimate, or other document, together with all schedules, attachments, amendments and supplements thereto (including all related or supporting information), supplied to or required to be supplied to any Governmental or Regulatory Authority responsible for the administration of Taxes.

"Termination Date" has the meaning ascribed thereto in Section 9.01(b)(i).

[redacted]

"Third-Party Claim" has the meaning ascribed thereto in Section 8.05(b).

"Title Commitment" means that certain Title Commitment issued by Stewart Title Guaranty Company as File Number 2013021 with respect to the Project Site.

"Tolling Agreement" means that certain Tolling Agreement between Seller (as assignee of Calpine Construction Finance Company, L.P.) and Purchaser, dated September 30, 2014.

"Transfer Taxes" has the meaning ascribed thereto in Section 5.09.

"U.S. Dollars" means the lawful currency of the United States.

Section 1.02 Certain Principles of Interpretation. In this Agreement, unless otherwise indicated, all words defined in the singular have the corresponding meaning in the plural and vice versa; words importing any gender include the other gender; references to statutes or regulations are to be construed as including all statutory or regulatory provisions consolidating, amending or replacing the statute or regulation referred to; references to "writing" include printing, typing, lithography and other means of reproducing words in a tangible visible form; the words "including", "includes" and "include" shall be deemed to be followed in each instance by the words "without limitation"; the words "shall" and "will" have the same meaning; references to articles, sections (or subdivisions of sections), exhibits, annexes or schedules are to articles, sections (or subdivisions of sections), exhibits, annexes or schedules of or to this Agreement; references to agreements and other contractual instruments shall be deemed to include all amendments, extensions and other modifications to such instruments (without, however, limiting any prohibition on any subsequent amendments, extensions and other modifications by the terms of this Agreement); references to Persons include their respective successors and permitted assigns and, in the case of Governmental or Regulatory Authorities, Persons succeeding to their respective functions and capacities; the phrase ordinary course of

business refers to the Business and the Project as currently conducted; and all accounting terms used herein and not expressly defined herein shall have the meanings given to them under GAAP.

ARTICLE II

PURCHASE AND SALE OF PURCHASED ASSETS; CLOSING

Section 2.01 Purchased Assets. Upon the terms and subject to the conditions contained in this Agreement, at the Closing, Seller shall sell, convey, grant, assign, transfer and deliver to Purchaser, and Purchaser shall purchase, acquire and accept title to and ownership from Seller, all of Seller's right, title and interest in and to the Project, the Project Site and assets, properties and rights, used in the Business as presently conducted, but in each case excluding all Excluded Assets (collectively, the "Purchased Assets"), with good title, free and clear of all Liens, other than Permitted Liens, including, without limitation:

(a) All Real Property;

(b) All Tangible Personal Property, except the Tangible Personal Property listed in Section 2.02(j) of the Seller Disclosure Schedule;

(c) All specialty tooling associated with the Business;

(d) All Company Contracts other than the Excluded Contracts, including any Contract entered into following the Effective Date that if in existence on the Effective Date would have been required to be disclosed on Section 3.13 of the Seller Disclosure Schedule, provided that such Contract was entered into in accordance with Section 5.03 and which Purchaser has expressly agreed to assume in writing (the "Purchased Contracts");

(e) All Governmental and Regulatory Approvals primarily related or otherwise material to the Property, the Project, the Project Site, the Purchased Assets or the Business other than the Excluded Governmental and Regulatory Approvals;

(f) All Books and Records;

(g) All Emission Allowances and all rights to any future Emission Allowances, if any, that will be granted or allocated to be held in accounts maintained with respect to the Project or in the name of Seller (other than those Emission Allowances used in the ordinary course of operation of the Project consistent with past practice prior to the Closing);

(h) All right, title, and interest of Seller, if any, in and to the name "Osprey Energy Center" except that Seller shall have the right after the Closing to retain the name "Osprey Energy Center" in the Excluded Books and Records;

(i) All Intellectual Property, other than the Excluded Intellectual Property;

(j) All unexpired warranties, indemnities, and guarantees made or given by manufacturers, overhaulers, assemblers, refurbishers, vendors, service providers and other comparable third parties to the extent relating to the Project, the Project Site or the Purchased Assets (but excluding those warranties, indemnities, and guarantees related to any Excluded

Assets), including the warranties and guarantees listed in Section 2.01(j) of the Seller Disclosure Schedule;

(k) All right, title, and interest of Seller in all Project Software and in all license, maintenance, support and escrow agreements pursuant to which Project Software is licensed for use by the Seller or for the Project or Business, excluding any such agreements as are Excluded Contracts; and

(l) All rights to any Actions or Proceedings of any nature available to or being pursued by Seller to the extent related to the Business, the Purchased Assets or the Assumed Liabilities, whether arising by way of counterclaim or otherwise, and whether known or unknown as of the date hereof or the Closing Date, but specifically excluding any such rights to Actions or Proceedings which are primarily related to Excluded Assets or Excluded Liabilities.

Section 2.02 Excluded Assets. Nothing in this Agreement shall constitute or be construed as conferring on Purchaser, and Purchaser shall not be entitled or required to purchase or acquire, and Seller shall not be required to sell, any right, title or interest in, to or under the following assets, interests, properties, rights, licenses, Permits or Contracts, whether real, personal, or mixed, whether accrued, contingent, or otherwise, and whether owned, leased, licensed or contracted for (collectively, the "Excluded Assets"):

(a) All of Seller's cash, cash equivalents, bank deposits and, to the extent relating to the period prior to Closing, accounts receivable, trade or otherwise;

(b) Inventory;

(c) All rights and interests of Seller arising under this Agreement, the Ancillary Agreements or any other instrument or document executed and delivered pursuant to the terms of this Agreement or relating in all material respects to the Excluded Assets;

(d) The Company Contracts listed in Section 2.02(d) of the Seller Disclosure Schedule, including any Contract entered into following the Effective Date that if in existence on the Effective Date would have been required to be disclosed on Schedule 3.13 of the Seller Disclosure Schedule and which Purchaser has not expressly agreed to assume in writing (the "Excluded Contracts");

(e) (i) Seller's certificate of formation and other organizational, corporate, administrative and regulatory documents and materials, qualifications to conduct business as a foreign entity, arrangements with registered agents relating to foreign qualifications and taxpayer and other identification numbers, (ii) the minute books, equity transfer books and company seal, membership certificates and other documents relating to the organization, maintenance and existence of Seller and any other books, records or documents relating primarily to the Excluded Assets or the Excluded Liabilities and (iii) the general ledger, all original tax returns of Seller and all tax returns not related to the Purchased Assets and all related items of Seller, including, but not limited to, all invoices and supporting documentation for all revenues and expenses (except for any expenses relating to the Purchased Contracts), for all Pre-Closing Periods (the "Excluded Books and Records");

(f) All refunds or credits, if any, of Taxes due to Seller or otherwise with respect to the Purchased Assets for any Pre-Closing Period;

(g) All rights of Seller in the name "Osprey Energy Center" as used in the Excluded Books and Records solely with respect to Seller's business as it exists immediately after the Closing;

(h) All Benefit Plans and all assets owned or held in trust or otherwise attributable thereto;

(i) The Governmental and Regulatory Approvals listed in Section 2.2(i) of the Seller Disclosure Schedule (the "Excluded Governmental and Regulatory Approvals"); and

(j) The Intellectual Property listed in Section 2.02(j) of the Seller Disclosure Schedule (the "Excluded Intellectual Property").

All references herein to the Purchased Assets shall be deemed not to include the Excluded Assets.

Section 2.03 Assumption of Liabilities. At the Closing, Purchaser shall assume and agree to pay, perform and discharge when due, and shall be liable with respect to, the following Liabilities of Seller and its Affiliates, but only to the extent that such Liabilities arise out of or are related to the ownership or operation of the Project, the Project Site, the Purchased Assets or the Business after the Closing (collectively, the "Assumed Liabilities"):

(a) All Liabilities of Seller or its Affiliates arising under the Purchased Contracts;

(b) All Liabilities of Seller under Governmental or Regulatory Approvals arising out of or relating to the ownership or operation of the Project, including those set forth in Section 3.18(a) of the Seller Disclosure Schedule;

(c) All Liabilities of Seller with respect to the Purchased Assets under applicable Law (including Environmental Laws) or Orders arising out of or relating to the ownership or operation of the Project after the Closing; and

(d) All Transfer Taxes for which Purchaser is liable under Section 5.09.

Section 2.04 Excluded Liabilities. Except for the Assumed Liabilities, Purchaser will not assume, be deemed to have assumed, or be responsible for any Liability with respect to or concerning (i) Seller (or any Affiliate of Seller) or (ii) the Project, the Project Site, the Purchased Assets or the Business, including, without limitation, the following (collectively, the "Excluded Liabilities"):

(a) All Liabilities of Seller or its Affiliates arising out of or related to the ownership or operation of the Project, the Project Site, the Purchased Assets or the Business prior to the Closing;

(b) All Liabilities of Seller or its Affiliates to the extent relating to any Excluded Assets;

(c) All Taxes of Seller, including those relating to, imposed on, asserted against or attributable to (i) the income, assets or operations of the Business, (ii) the ownership of the Purchased Assets or (iii) any Taxes for which the Company or its Affiliates is otherwise liable and all Transfer Taxes for which Seller is liable under Section 5.09;

(d) All Liabilities of Seller or its Affiliates for fees and expenses payable to lenders, brokers, financial advisors, legal counsel, accountants and other professionals engaged by Seller or its Affiliates in connection with this Agreement;

(e) All trade and other accounts payable of Seller and other Liabilities of Seller to pay suppliers and third parties to the extent arising from the conduct of the Business or related to the Purchased Assets, in each case relating to events which occur prior to the Closing, to the extent not settled prior to the Closing;

(f) All Liabilities arising out of, in respect of or in connection with the failure by Seller or any of its Affiliates to comply with any Contract, Law, Governmental and Regulatory Approval or Order;

(g) All Liabilities of Seller or any Affiliate thereof representing Indebtedness;

(h) All Liabilities of Seller, the Operator or any of either of their Affiliates and all Controlled Group Liability with respect to any of the foregoing arising under or in connection with any Benefit Plan or other arrangement providing benefits to any present or former employee or other service provider of Seller, Operator or any Affiliate or ERISA Affiliate of Seller or Operator (or any relatives of any such present or former employee or service provider);

(i) All Liabilities of Seller, the Operator or any of either of their Affiliates with respect to any present or former employees, officers, directors, retirees, independent contractors or consultants of Seller or the Operator or any of either of their Affiliates including, without limitation, any Liabilities associated with any claims for salary, wages or other benefits, bonuses, accrued vacation, workers' compensation, severance, retention, termination or other similar payments; and

(j) All Environmental Claims, or Liabilities under Environmental Laws, to the extent arising out of or relating to facts, circumstances or conditions existing on or prior to the Closing Date.

Section 2.05 Closing. The closing of the transactions described in this Agreement (the "Closing") shall take place at the offices of White & Case LLP, counsel to Seller, at 1155 Avenue of the Americas, New York, New York 10036, or at such other place as Purchaser and Seller shall mutually agree, at 10:00 A.M. Eastern time, on the Closing Date, subject to the satisfaction or waiver of the conditions to Closing set forth in Article VI and Article VII hereto. At the Closing, (i) Purchaser shall pay the Closing Payment to Seller by wire transfer of immediately available funds in U.S. Dollars to such account(s) as Seller may direct by written notice delivered to Purchaser at least three (3) Business Days before the Closing Date, and (ii) each of Purchaser and Seller shall cause to be delivered to the other the documents and instruments required to be delivered under Articles VI and VII. The Closing shall be effective for

financial and accounting purposes as of 11:59 p.m. on the day immediately preceding the Closing Date.

Section 2.06 Purchase Price.

(a) The cash purchase price payable at the Closing for the Purchased Assets shall be an amount equal to the sum of, (i) one hundred sixty six million dollars ($166,000,000.00) (the "Base Purchase Price"), [redacted] (such aggregate amount, the "Closing Payment").

(b) Subject to the terms of Section 8.09, at the Closing, Purchaser will deposit the Indemnity Escrow Amount with [redacted] (the "Escrow Agent"), by wire transfer of immediately available funds, to be held by the Escrow Agent in a separate account (the "Indemnity Escrow Account") pursuant to the terms of the Escrow Agreement. The Indemnity Escrow Amount will be available to satisfy any indemnification obligations of Seller pursuant to Section 8.02(a)(i), subject to the terms and conditions of this Agreement and the Escrow Agreement. Subject to the terms and conditions of this Agreement and the Escrow Agreement, the term of the Indemnity Escrow Account will be for a period of eighteen (18) months following the Closing Date (the "Indemnity Escrow Period"), subject to the provisions of the Escrow Agreement. The Indemnity Escrow Amount, plus any interest accrued thereon (collectively, the "Indemnity Escrow Fund") will be held by the Escrow Agent and disbursed in accordance with Section 8.08 of this Agreement and the Escrow Agreement.

Section 2.07 Further Assurances; Post-Closing Cooperation.

(a) Subject to the terms and conditions of this Agreement, at any time or from time to time after the Closing, each of the parties hereto shall execute and deliver such other documents and instruments, provide such materials and information, and take such other actions as may reasonably be necessary, proper or advisable, to the extent permitted by Law, to fulfill its obligations under this Agreement.

(b) For a period extending four (4) years after the Closing Date, each party will afford the other party, its counsel and its accountants, during normal business hours, reasonable access to the books, records and other data, documents or reports relating to the business or financial or operating condition of the Business in its possession with respect to periods prior to the Closing Date and the right to make copies and extracts therefrom, to the extent that such access may reasonably be required by the requesting party in connection with (i)

the preparation of Tax Returns or financial statements, (ii) compliance with the requirements of any Governmental or Regulatory Authority, or (iii) in connection with any actual or threatened Action or Proceeding.

(c) Notwithstanding anything to the contrary contained in this Section 2.07, if the parties are in an adversarial relationship in any Action or Proceeding, the furnishing of information, documents or records in accordance with any provision of this Section 2.07 shall be subject to applicable rules relating to discovery.

Section 2.08 Purchase Price Allocation. Within one hundred and eighty (180) days following the Closing, Purchaser shall deliver to Seller a proposed allocation of the Purchase Price, as determined in accordance with U.S. federal income tax principles (the "Tax Purchase Price") among the Purchased Assets in accordance with Section 1060 of the Code and Treasury Regulations thereunder (and any similar provision of state, local or foreign law, as applicable). Seller shall have thirty (30) days following receipt of Purchaser's proposed allocation to provide any changes or objections; in the absence of any such changes or objections, Purchaser's proposed allocation shall be deemed to have been agreed. If Seller objects in writing to Purchaser's proposed allocation within such thirty (30) day period, then the parties shall cooperate in good faith to reach a mutually agreeable allocation. If the parties cannot agree on an appropriate allocation of the Tax Purchase Price (as adjusted) within thirty (30) days of the receipt of Seller's written objection, either party may submit any disputes to the Independent Accountant. The Independent Accountant shall be instructed to resolve such disagreement within thirty (30) days after it is engaged to resolve the matter. The fees, costs and expenses of the Independent Accountant incurred shall be paid fifty percent (50%) by Seller and fifty percent (50%) by Purchaser. Seller and Purchaser hereby undertake and agree to file timely any information that may be required to be filed pursuant to Treasury Regulations promulgated under Section 1060(b) of the Code, and shall use the allocation determined pursuant to this Section 2.08 in connection with the preparation of Internal Revenue Service Form 8594 as such form relates to the transactions contemplated by this Agreement. Neither Purchaser nor Seller shall take any position (including in any Tax Returns, reports, audits or otherwise) that is inconsistent with such allocation, unless otherwise required pursuant to a final determination by a court of competent jurisdiction or pursuant to a closing agreement with the Internal Revenue Service entered into pursuant to Section 7121 of the Code. In the event that the final allocation is disputed by any Tax authority, the relevant party who receives notice of such dispute will promptly notify the other party, and the parties will consult in good faith as to how to resolve such dispute in a manner consistent with such allocation. Any amount treated as an adjustment to the Purchase Price after the date a final allocation is determined pursuant to this Section 2.08 shall result in an adjusted allocation determined consistent with the allocation methodology previously agreed to by the parties and each party shall file any returns or forms required under Treasury Regulation 1.1060-1(e)(1)(ii)(B) for such adjustment .

ARTICLE III

REPRESENTATIONS AND WARRANTIES OF SELLER

Seller hereby represents and warrants to Purchaser as follows, except as set forth in the disclosure schedule delivered by Seller to Purchaser concurrently with the execution and delivery of this Agreement (the "Seller Disclosure Schedule"):

Section 3.01 Legal Existence. Seller is a limited liability company duly formed, validly existing and in good standing under the Laws of the State of Delaware. Seller is qualified to do business and is in good standing in the states in which the conduct of the Business or locations of its assets and properties makes such qualification necessary, except where failure to be so qualified or to be in good standing would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect or a material adverse effect on Seller's ability to perform its obligations hereunder. Seller has all requisite limited liability company power and authority to execute, deliver and perform its obligations under this Agreement, including to sell the Purchased Assets pursuant hereto, and the Ancillary Agreements to which it is a party.

Section 3.02 Authority. The execution and delivery by Seller of, and the performance by Seller of its obligations under, this Agreement and the Ancillary Agreements to which it is a party and the consummation by Seller of the transactions contemplated hereby and thereby have been duly and validly authorized by all necessary limited liability company action on the part of Seller, with no other actions or proceedings on the part of Seller being necessary. This Agreement has been, and each of the Ancillary Agreements to which it is party have been or will be, duly and validly executed and delivered by Seller and, assuming the due authorization, execution and delivery thereof by the other parties thereto, constitutes the legal, valid and binding obligation of Seller enforceable against Seller in accordance with their respective terms, except as the same may be limited by (a) applicable bankruptcy, insolvency, reorganization, moratorium and other similar Laws of general application affecting the rights and remedies of creditors and (b) general principles of equity (regardless of whether such enforcement is considered in a proceeding in equity or at law).

Section 3.03 No Conflicts. The execution and delivery by Seller of, and the performance by Seller of its obligations under, this Agreement and each of the Ancillary Agreements to which it is a party and the consummation of the transactions contemplated hereby and thereby will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the certificate of formation of Seller or its other organizational documents;

(b) subject to obtaining the approvals, consents and actions, making the filings and giving the notices set forth in Section 3.04 of the Seller Disclosure Schedule, conflict with or result in a violation or breach of any term or provision of any material Law or Order applicable to the Company or the Purchased Assets;

(c) except as set forth in Section 3.03(c) of the Seller Disclosure Schedule, (i) conflict with or result in a violation or breach of, (ii) constitute (with or without notice, lapse of

time or both) a material default (or give rise to any right of termination, cancellation or acceleration) under, or (iii) conflict with or result in a violation or breach of, or give to any Person any right of termination, consent, cancellation, acceleration or modification in or with respect to, any Company Contract that is a Purchased Contract, material Permit or material Governmental or Regulatory Approval to which the Company is a party or by which any of its assets and properties, including the Purchased Assets is bound; or

(d) result in the creation or imposition of any Lien on the Purchased Assets, other than Permitted Liens.

Section 3.04 Governmental or Regulatory Approvals; Filings. Except as set forth in Section 3.04 of the Seller Disclosure Schedule, no Governmental or Regulatory Approval on the part of Seller is required in connection with the execution and delivery by Seller of this Agreement or the consummation of the transactions contemplated hereby, except where the failure to obtain any such Governmental or Regulatory Approval would not reasonably be expected to have a material adverse effect on the Purchased Assets or the ability of Seller to perform its obligations hereunder.

Section 3.05 Financial Statements and Condition. Prior to the execution of this Agreement, Seller has delivered to Purchaser true, correct and complete copies of the following financial statements of the Company (the "Financial Statements"):

(a) the unaudited pro forma balance sheet of the Company as of December 31, 2013; and

(b) the unaudited pro forma balance sheet of the Company as of October 31, 2014.

(c) All Financial Statements (and the financial statements required to be furnished to Purchaser pursuant to Section 5.12) (i) were prepared from the books and records of the Company, which books and records are correct and complete in all material respects, and in accordance with GAAP (excluding any required provision for income taxes and footnotes) using the same accounting principles, policies and methods as have historically been used in connection with the calculation of the items reflected thereon, and (ii) fairly present in all material respects the financial condition and results of operations of the Company as of the respective dates thereof, subject to year-end audit adjustments in the ordinary course of business and the absence of footnotes thereto.

Section 3.06 No Undisclosed Liabilities. There are no Liabilities with respect to the Business, the Purchased Assets or the Assumed Liabilities required to be disclosed on a balance sheet prepared in accordance with GAAP, except (i) Liabilities that are reflected on or reserved against in the Financial Statements, to the extent so reflected or reserved thereon, (ii) Liabilities set forth in Section 3.06 of the Seller Disclosure Schedule, (iii) Liabilities incurred since October 31, 2014, in the ordinary course of business, and (iv) other Liabilities which do not exceed $500,000 individually or $1,000,000 in the aggregate.

Section 3.07 Absence of Changes. Except as set forth in Section 3.07 of the Seller Disclosure Schedule, (a) since December 31, 2013, the Business has been operated, in all

material respects, in the ordinary course of business consistent with past practice, (b) since December 31, 2013, there has not been any change, event, effect or occurrence that has had or is reasonably expected to have a Material Adverse Effect and (c) since October 31, 2014, Seller has not taken any of the actions set forth in Section 5.03(a)-(n).

Section 3.08 Compliance with Laws. Except as set forth in Section 3.08 of the Seller Disclosure Schedule, the Business, the Project, the Project Site and the Purchased Assets are, and since January 1, 2013, have been, in material compliance with all applicable Orders and Laws.

Section 3.09 Legal Proceedings. Except as set forth in Section 3.09 of the Seller Disclosure Schedule, there are no material Actions or Proceedings pending or, to the Knowledge of Seller, threatened against Seller or its Affiliates and arising out of or related to the ownership or operation of the Project, the Project Site, the Business or the Purchased Assets.

Section 3.10 Real Property. Section 3.10(a) of the Seller Disclosure Schedule sets forth a list of all real property (including easements and rights-of-way) owned in fee by the Company or, as to any easements and rights of way, in which the Company has an interest (the "Real Property"). The Company has good and indefeasible title to all Real Property, free and clear of all Liens other than Permitted Liens. The Company does not lease any real property. Except as set forth in Section 3.10(b) of the Seller Disclosure Schedule, the Company has not received any written notice from any Governmental or Regulatory Authority regarding the condemnation of any material portion of the Real Property, and there is no pending or, to the Knowledge of Seller, threatened actions of a similar nature in connection with any Real Property. To the knowledge of Seller, no portion of the Real Property (i) is subject to any designation or preliminary determination of any Governmental or Regulatory Authority as an archeological site, as an historical site, or under the Endangered Species Act, and there are no cemeteries or burial sites on the Real Property, or (ii) is in violation in any material respect of any applicable zoning, flood, building or other Law, or any other similar legal requirement relating to real property. To the knowledge of Seller, (i) the Real Property has legal and physical access to Derby Avenue, and (ii) no Person has any right to enter or cross the Real Property for access, parking or otherwise. The "gates" or access points between the Real Property and the contiguous property leased or owned by Seller's Affiliate Auburndale Peaker Energy Center, LLC, and, to the knowledge of Seller, any other "gates" or access points shown on the Survey, may be immediately and permanently closed by the owner of the Real Property. There are no parties, other than Seller, in possession of, nor any lease or other agreements for the use, occupancy or possession of all or any portion of the Real Property. Notwithstanding anything herein to the contrary, "knowledge of Seller" as such term is used in this Section 3.10 shall mean the actual knowledge of those Persons listed in Section 1.01(b) of the Seller Disclosure Schedule, without due inquiry.

Section 3.11 Personal Property. Except as set forth in Section 3.11 of the Seller Disclosure Schedule, the Seller has good title to all of the material Purchased Assets (other than the Real Property and the Intellectual Property) free and clear of all Liens other than Permitted Liens. Except as set forth in Section 3.11 of the Seller Disclosure Schedule, the Company has good title to, or valid leasehold interests in, all material Tangible Personal Property necessary for or used in connection with the Business and the Project, free and clear of all Liens other than Permitted Liens. Except as set forth in Section 3.11 of the Seller Disclosure Schedule, no

Tangible Personal Property used by the Company in the Business or for the Project is owned by any Affiliate of the Company or any third party.

Section 3.12 Intellectual Property. Seller possesses or has the right to use all material patents, trademarks, service marks, domain names, trade secrets, know-how, data and copyrights and all goodwill associated therewith (collectively, the "Intellectual Property") that are necessary for the conduct of the Business or used in the operation, maintenance or testing of the Project. Seller has not received from any third party any claim in writing that Seller is infringing upon Intellectual Property of a third party, and, to the Knowledge of Seller, it is not otherwise, infringing upon any material Intellectual Property of a third party. To the Knowledge of Seller, no Person is infringing, violating, misappropriating or otherwise misusing any of Seller's material Intellectual Property, and Seller has not made any such claims against any Person. Seller does not own any registered Intellectual Property and Seller is not the registrant of any Internet domain names.

Section 3.13 Company Contracts. (a) Section 3.13 of the Seller Disclosure Schedule sets forth a true, correct and complete list of the following Contracts as of the date hereof to which the Company (or an Affiliate of the Company) is a party or by which any of its assets or properties is bound which relate primarily to the Project, the Project Site, the Purchased Assets or the Business (collectively, the "Company Contracts"), with the exception of the Excluded Contracts:

(i) all Contracts for the purchase, exchange or sale of water, natural gas, electric power or ancillary services;

(ii) all Contracts for the transportation or transmission of natural gas and electric power;

(iii) all interconnection Contracts;

(iv) all Contracts with respect to storage, parking, loaning, distribution, wheeling, facility or meter construction, unloading, delivery or balancing of natural gas;

(v) all Contracts with any Governmental or Regulatory Authority but excluding Permits;

(vi) all Contracts involving the disposal of Hazardous Substances;

(vii) all Contracts that limit or purport to limit the ability of Seller to compete in any line of business or with any Person or in any geographic area or during any period of time;

(viii) all long-term service or maintenance Contracts;

(ix) all Contracts relating to Indebtedness or imposing Liens for borrowed money on the Purchased Assets;

(x) all Contracts representing guaranty or surety obligations or similar agreements;

(xi) all Contracts which provide for an interest rate, currency, equity, credit or commodity swap, cap, floor or collar, spot or foreign exchange transaction, cross-currency rate swap, currency option, any combination thereof, or option with respect to, any of the foregoing or any similar transactions, for the purpose of hedging the Company's exposure to fluctuations in the price of commodities, including electric power, in any form, including energy, capacity or any ancillary services, gas, coal, oil or other commodities, currencies, interest rates and indices, and any financial transmission rights and auction revenue rights;

(xii) except as described above, each other Contract (A) for the future sale or acquisition of any asset or property or (B) that grants a right or option to purchase any asset or property or receive any services, other than any Contract relating to any asset or property with a value of less than $100,000;

(xiii) all Contracts between or among the Company, on the one hand, and any Affiliate of the Company, on the other hand;

(xiv) All material Contracts pursuant to which Intellectual Property is licensed;

(xv) all Contracts pursuant to which material Software which is a Purchased Asset is licensed or that relate to the maintenance, support, escrow, subscription, access or services associated with such Software; and

(xvi) each other Contract requiring payments by or to the Company in excess of $100,000 per annum.

(b) Each Company Contract that is a Purchased Contract constitutes a legal, valid and binding obligation of the Company, and, to the Knowledge of Seller, the other parties thereto, enforceable in accordance with its terms. Neither the Company nor, to the Knowledge of Seller, any other party to any Company Contract that is a Purchased Contract is, in material violation or breach of or in material default under any such Company Contract that is a Purchased Contract.

(c) Seller (i) has provided or made available to Purchaser true, correct and complete copies of all Company Contracts which are not Excluded Contracts in existence on the Effective Date and (ii) will provide or make available to Purchaser true, correct and complete copies of all Company Contracts which are not Excluded Contracts entered into after the Effective Date promptly following their execution.

Section 3.14 Taxes. Except as set forth in Section 3.14 of the Seller Disclosure Schedule, (i) with respect to the income or operations of the Business or ownership of the Purchased Assets all material Tax Returns required to be filed on or prior to date hereof have been timely filed or will be timely filed (in each case, taking into account any available extensions) in accordance with applicable Law, and all such Tax Returns are true, correct and complete in all material respects, and accurately reflect all material liability for Taxes of, or with respect to the income or operations of the Business or ownership of the Purchased Assets for the periods covered thereby, (ii) all material Taxes of, or with respect to the income or operations of the Business, or ownership of the Purchased Assets that are due and owing have been paid in full

within the time required by Law to the appropriate Tax authority, (iii) there are no material audits, contests, disputes, claims, assessments, levies, administrative or judicial proceedings pending, or proposed in writing with respect to the income or operations of the Business or ownership of the Purchased Assets by any Tax authority, (iv) the Company has timely withheld and paid to the appropriate Tax authority all material Taxes required to have been withheld and paid on or prior to the date hereof, including those Taxes in connection with amounts paid or owing to any employee, independent contractor, creditor, member or other third party, (v) no waiver or extension of any statute of limitations with respect to any material Tax filing or payment obligation pertaining to the Company or the income or operations of the Business or ownership of the Purchased Assets, is currently in effect, (vi) there are no Liens for Taxes upon any of the Purchased Assets other than Permitted Liens, (vii) the Company is not presently contesting material Tax liability with respect to the income or operations of the Business or ownership of the Purchased Assets before any court, Tax authority, tribunal or agency, and (viii) there are no Tax sharing, allocation, indemnification or similar agreements in effect as between any of the Company or any predecessor or Affiliate thereof and any other party under which Purchaser could be liable for any material Taxes or other claims of any party. It is agreed and understood that this Section 3.14, Section 3.05 and Section 3.15 contain the sole and exclusive representations and warranties provided with respect to all matters relating to Taxes of or with respect to the Business and the Purchased Assets.

Section 3.15 Employee Matters.

(a) Section 3.15(a) of the Seller Disclosure Schedule contains a list of each Benefit Plan. With respect to each Benefit Plan, Seller has made available to Purchaser copies of all plan documents and any other material related documents, including all amendments thereto.

(b) Each Benefit Plan (and any related trust or other funding vehicle) has been maintained, operated and administered in compliance with applicable Laws and with the terms of such Benefit Plan (including the making of any required contributions), except where the failure to so comply would not reasonably be expected to result in a material liability to the Company. Each Benefit Plan that is intended to be qualified within the meaning of Section 401(a) of the Code either (i) has received a current favorable determination letter from the Internal Revenue Service with respect to all plan document qualification requirements for which the applicable remedial amendment period under Section 401(b) of the Code has closed with any amendments required by such determination letter made as and when required by such determination letter or an application for such a favorable determination letter has been timely filed and remains pending, or (ii) has been duly adopted using a prototype or volume submitter document with respect to which the Company is properly relying on an opinion or advisory letter issued by the Internal Revenue Service, and in either case of (i) or (ii) nothing has occurred, whether by action or failure to act, that would reasonably be expected to cause the loss of such qualification.

(c) Except as set forth on Section 3.15(c) of the Seller Disclosure Schedule, none of the execution, delivery or performance of this Agreement or the consummation of the transactions contemplated hereby (alone or in combination with any other event, including any termination of employment on or following the Closing) will (i) entitle any Facility Employee to any compensation or benefit, (ii) accelerate the time of payment or vesting, or trigger any

payment or funding, of any compensation or benefits or (iii) result in any breach or violation of, or default under, or limit any rights to amend, modify or terminate, any Benefit Plan.

(d) Neither the Company nor the Operator has sponsored, maintained or contributed to, or been required to maintain or contribute to, any benefit plan that is subject to Section 302 or 303 or Title IV of ERISA or Section 412 or 430 of the Code. There does not exist, nor do any circumstances exist that could result in, any Controlled Group Liability for which the Purchaser or any of its Affiliates could be responsible after the Closing.

(e) No Benefit Plan provides or has any obligation to provide, or makes any payment or has any obligation to make any payment with respect to, health, medical or other welfare benefits, after retirement or other termination of employment (other than for continuation coverage required under Section 4980B(f) of the Code) ("Retiree Benefits") to or for any Facility Employee or any relative thereof, and none of the Company, the Operator or any of their ERISA Affiliates provides or has any obligation to provide, or makes any payment or has any obligation to make any payment with respect to, Retiree Benefits to or for any Facility Employee or relative thereof.

(f) None of the Company, the Operator nor any of their Affiliates is a party to any collective bargaining agreement with any labor union representing the Facility Employees. No union certification or decertification proceeding has been filed and, to the Knowledge of Seller, no union authorization card campaign or other union organizing activity has been conducted relating to the Facility Employees within the past three (3) years. Except as set forth on Section 3.15(f) of the Seller Disclosure Schedule, within the past three (3) years, there have been no strikes, lockouts or other labor stoppages involving the Facility Employees, nor, to the Knowledge of Seller, are any strikes, lockouts or other labor stoppages pending or threatened. The Company, the Operator and their Affiliates are in compliance in all material respects with all Laws respecting labor, employment, immigration, fair employment practices, terms and conditions of employment, workers' compensation, occupational safety, plant closings and mass layoffs, wages and hours, equal employment opportunity, nondiscrimination, employment and reemployment rights of members of the uniformed services and classification of workers as employees or independent contractors, in each case with respect to the Facility Employees.

Section 3.16 Insurance. Section 3.16(a) of the Seller Disclosure Schedule contains a list of all material insurance policies currently in effect, that insure the Business as currently conducted and the Purchased Assets, including the Project, or affect or relate to the ownership, use or operation of any of the Purchased Assets, including the Project, and that have been issued to or for the benefit of the Company (such policies, the "Project Insurance Policies"). As of the date hereof, each such Project Insurance Policy is valid and binding and in full force and effect, and since June 1, 2013, the Company has not received any written notice of cancellation or termination in respect of any such policy or is in material default under any such policy. The Company has not failed to give, in a timely manner, any notice required under any of such Project Insurance Policies to preserve, in all material respects, its rights thereunder. Section 3.16(b) of the Seller Disclosure Schedule further sets forth, as of the date hereof, an accurate and complete list of all material claims asserted by Seller pursuant to any Project Insurance Policy since January 1, 2013, and describes the nature and status of such claims.

Section 3.17 Environmental Matters. Except as set forth in Section 3.17(a) of the Seller Disclosure Schedule:

(a) The Company and the Project are, and have been since January 1, 2008, in material compliance with all Environmental Laws in connection with their ownership, use, maintenance and operation of the Project and the Project Site and the Real Property;

(b) The Company and the Project have obtained all material permits and approvals required under Environmental Laws for the operation of the Project ("Environmental Permits"), and all such Environmental Permits are listed in Section 3.17(b) of the Seller Disclosure Schedule. All such Environmental Permits are in good standing, and the Company and Project are, and have been since January 1, 2008, in compliance in all material respects with the terms and conditions of all such Environmental Permits;

(c) The Company has not received any written notice, complaint, request for information, claim, demand or similar communication from any Governmental or Regulatory Authority or other Person, whether based in contract, tort, implied or express warranty, strict liability, or any other common law theory, or any criminal or civil statute (including any Environmental Law, Permit, Order, or agreement with any Governmental or Regulatory Authority or other Person), which is or could reasonably be expected to be material, arising from or with respect to (i) the presence of any Hazardous Substance or any other environmental conditions or a release or threatened release on, in or under the Project Site or the Real Property, (ii) any other circumstances forming the basis of any actual or alleged violation by the Company of any Environmental Law or liability of the Company under any Environmental Laws, (iii) any remedial or removal action required to be taken by the Company under any Environmental Law, or (iv) any harm, injury or damage to real or personal property, natural resources, the environment or any person alleged to have resulted from the foregoing;

(d) No material lawsuits, claims, proceedings, investigations or enforcement actions are pending or, to Seller's Knowledge, threatened in writing under any Environmental Law with respect to the Company, the Project, the Project Site or the Real Property;

(e) No Hazardous Substances are or have been released, buried, discharged, spilled or disposed of on, or migrated from or onto, the Project Site or the Real Property resulting in existing contamination, and to the Seller's Knowledge, no environmental condition exists or event has occurred (including, without limitation, the presence, release or threatened release or disposal of Hazardous Substances) related to the Project Site or the Real Property or to the Company's past or present operations which with the passing of time or the giving of notice or both would constitute a material violation of any Environmental Law or otherwise give rise to material costs, liabilities or obligations under any Environmental Law;

(f) Neither the Company nor its predecessors in interest have transported or disposed of, or arranged for or permitted the transportation or disposal of, any Hazardous Substances to any location (i) which is listed on the National Priorities List or the CERCLIS list under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, (ii) which, to Seller's Knowledge, is the subject of any federal, state or local enforcement action or other investigation to which Seller is a party, or (iii) about which the

Company has received or has reason to expect to receive a potentially responsible party notice or similar notice under any Environmental Law; and

(g) No environmental Lien (which is not a Permitted Lien) has attached or is threatened in writing to be attached to the Project Site or the Real Property.

This Section 3.17, and to the extent applicable, Section 3.18(a) contains the sole and exclusive representations and warranties of Seller with respect to environmental matters including all matters arising under any Environmental Laws or related to Hazardous Substances

Section 3.18 Permits and Regulatory Matters. Section 3.18(a) of the Seller Disclosure Schedule sets forth all material Governmental or Regulatory Approvals owned or held by the Company as of the date hereof and which are necessary or required for the ownership, occupancy, management and operation of the Project, the Project Site, the Purchased Assets or the Business, as currently conducted.

(a) Seller has not received any written notice from any Governmental or Regulatory Authority that any of its properties, facilities, equipment, operations or business procedures or practices fails to comply in any material respect with any Permit or Governmental or Regulatory Approvals.

(b) Except as set forth in Section 3.18(b) of the Seller Disclosure Schedule, all Permits and Governmental or Regulatory Approvals required to be set forth in Section 3.18(a) of the Seller Disclosure Schedule are in full force and effect, and the Company is, and since January 1, 2013, has been, in compliance in all material respects with all such Permits and Governmental or Regulatory Approvals.

Section 3.19 Brokers. None of the Company nor any of its Affiliates has or will have any liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the execution and delivery of this Agreement or the consummation of the transactions contemplated hereby.

Section 3.20 Condition of Assets; Interdependencies.

(a) Except as set forth in Section 3.20 of the Seller Disclosure Schedule, as of the date hereof, the buildings, plants, structures and fixtures and the machinery, furniture, equipment, vehicles and other items of Tangible Personal Property included in the Purchased Assets are structurally sound, are in good operating condition and repair (including the scheduling and timely execution of all routine maintenance, preventative maintenance and major maintenance consistent with the past practice of Seller), ordinary wear and tear excepted, and are adequate for the uses to which they are being put, and as of the date hereof, none of such buildings, plants, structures and fixtures and the machinery, furniture, equipment, vehicles and other items of Tangible Personal Property is in need of maintenance or repairs except for ordinary, routine maintenance and repairs that will be completed on a timely basis and are not material in nature or cost, except as set forth in the major maintenance projects listed in Section 5.02(a), Item (b) of the Purchaser Disclosure Schedule. Except as set forth in Section 3.20(a) of the Seller Disclosure Schedule, Seller has conducted the Business and operated and maintained

the Project and the Purchased Assets in accordance with Good Utility Practice and in accordance with past practice.

(b) Section 3.20(b) of the Seller Disclosure Schedule sets forth in reasonable detail a list of the interdependencies between the Project and the Auburndale Peaking Energy Center, a facility adjoining the Project which is also owned by Calpine Corporation ("APEC"), such list to include, without limitation, any physical interdependencies, staffing interdependencies as well as any interdependent contracts, permits or agreement between the Project and APEC.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF PURCHASER

Except as set forth in the disclosure schedule delivered by Purchaser to Seller concurrently with the execution and delivery of this Agreement (the "Purchaser Disclosure Schedule"), Purchaser hereby represents and warrants to Seller as follows:

Section 4.01 Legal Existence. Purchaser is a corporation duly formed, validly existing and in good standing under the Laws of the State of Florida. Purchaser has all requisite corporate power and authority to execute, deliver and perform its obligations under this Agreement, including to purchase the Purchased Assets pursuant hereto and the Ancillary Agreements to which it is a party.

Section 4.02 Authority. The execution and delivery by Purchaser of, and the performance by Purchaser of its obligations under, this Agreement and the Ancillary Agreements to which it is a party and the consummation by Purchaser of the transactions contemplated hereby and thereby have been duly and validly authorized by all necessary action on the part of Purchaser, with no other actions or proceedings on the part of Purchaser being necessary. This Agreement has been, and each of the Ancillary Agreements to which it is a party has been or will be, duly and validly executed and delivered by Purchaser and, assuming the due authorization, execution and delivery thereof by the other parties hereto, constitutes the legal, valid and binding obligation of Purchaser enforceable against Purchaser in accordance with their respective terms, except as the same may be limited by (a) applicable bankruptcy, insolvency, reorganization, moratorium and other similar Laws of general application affecting the rights and remedies of creditors and (b) general principles of equity (regardless of whether such enforcement is considered in a proceeding in equity or at law).

Section 4.03 No Conflicts. The execution and delivery by Purchaser of, and the performance by it of its obligations under, this Agreement and each of the Ancillary Agreements to which it is a party and the consummation of the transactions contemplated hereby and thereby will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the other organizational or constitutional documents of Purchaser;

(b) subject to obtaining the approvals, consents and actions, making the filings and giving the notices set forth in Section 4.04 of the Purchaser Disclosure Schedule, conflict with or result in a violation or breach of any term or provision of any material Law or Order applicable to Purchaser or any of its assets and properties; or

(c) except as set forth in Section 4.03 of the Purchaser Disclosure Schedule, (i) conflict with or result in a violation or breach of, (ii) constitute (with or without notice, lapse of time or both) a material default (or give rise to any right of termination, cancellation or acceleration) under, or (iii) require Purchaser to obtain any consent, approval or action of, make any filing with or give any notice to any Person as a result or under the terms of, any material Contract, Permit or Governmental or Regulatory Approval to which Purchaser is a party or by which any of its assets and properties is bound.

Section 4.04 Governmental or Regulatory Approvals. Except as set forth in Section 4.04 of the Purchaser Disclosure Schedule, no Governmental or Regulatory Approval on the part of Purchaser is required in connection with the execution and delivery by Purchaser of this Agreement or the consummation of the transactions contemplated hereby.

Section 4.05 Legal Proceedings. There are no Actions or Proceedings pending or, to the Knowledge of Purchaser, threatened against Purchaser or any of its assets or properties that would reasonably be expected to result in the issuance of an Order restraining, enjoining or otherwise prohibiting or making illegal the purchase by Purchaser of the Purchased Assets under this Agreement or the performance by Purchaser of its obligations under this Agreement or the Ancillary Agreements to which it is a party.

Section 4.06 Investment Representations. Purchaser is an investor experienced (or owned or managed by Persons experienced) in evaluating investments and, in particular (either on its own or with advisors), power generation facilities and has the knowledge, experience and resources to enable it to evaluate and to bear the risks of the investment contemplated hereunder.

Section 4.07 Brokers. Purchaser has no liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the execution and delivery of this Agreement.

Section 4.08 Due Diligence Investigation. Purchaser or its Representatives have had the opportunity to conduct their own independent investigation, review and analysis of the Project, the Project Site, Real Property, the Purchased Assets, the Business and the Assumed Liabilities, the results of operations, financial condition and prospects of the Business and the Project as they have deemed necessary or advisable in connection with entering into this Agreement and the related documents and the transactions contemplated hereby and thereby. As of the date hereof, Purchaser and its Representatives have been provided with all requested access to the Project, the Project Site, the Purchased Assets, the Business and the Assumed Liabilities for such purpose.

Section 4.09 Funds. Purchaser has on the date hereof, and will have on the Closing Date, sufficient cash on hand (and has provided Seller with evidence thereof) to enable Purchaser to purchase the Purchased Assets at the Closing in accordance with the terms and conditions of

this Agreement and to make all other necessary payments of fees and expenses in connection with the transactions contemplated hereby.

Section 4.10 Exon-Florio. Purchaser is not deemed a "foreign person" for purposes of Section 721 of the Defense Production Act of 1950, as amended, or any executive orders, rules or regulations relating thereto.

Section 4.11 Reliance on Seller's Representations and Warranties. In entering into this Agreement, Purchaser has relied solely upon its own independent review and analysis and the representations, warranties and covenants contained in Article III, or in any certificate delivered hereunder by Seller, and has not been induced by and has not relied upon any representations, warranties or statements, whether oral or written, express or implied, made by Seller or any of its Representatives, Affiliates or agents that are not expressly set forth in Article III of this Agreement or in any certificate delivered hereunder by Seller, and except as specifically set forth in Article III of this Agreement or in any certificate delivered hereunder by Seller, Seller does not make and has not made any representations or warranties of any kind, express or implied, written or oral, as to projections, forecasts or estimates of cash flows, yields or returns. Neither Seller nor any of its Representatives, Affiliates or agents shall have any liability or responsibility whatsoever to Purchaser or its Representatives, shareholders, Affiliates or agents on any basis (including, without limitation, in contract or tort, under federal or state securities Laws or otherwise), resulting from the furnishing to Purchaser, or from Purchaser's use of, any information or documents, provided, however, that the foregoing is not intended to limit Seller's representations or warranties set forth in Article III of this Agreement or in any certificate delivered hereunder by Seller, or claims for fraud or intentional misrepresentation.

ARTICLE V

COVENANTS

Section 5.01 Investigation by Purchaser. From the date hereof until the Closing, Seller shall provide Purchaser and its Representatives with reasonable access, upon reasonable prior notice and during normal business hours, to the officers, employees, agents, engineers, and accountants of the Company and the Company's assets, properties, books and records, but in each case only to the extent that such access does not unreasonably interfere with the business and operations of the Company; provided, that (i) Seller shall not be required to furnish any such information where the furnishing of such information would violate any Law, Order, Company Contract, Permit or Governmental or Regulatory Approval applicable to Seller or any of its assets and properties, including the Project, the Project Site, the Purchased Assets, the Business and the Assumed Liabilities, (ii) Purchaser and Purchaser's Representatives shall comply with all applicable safety rules, regulations and procedures implemented by Seller as to which Purchaser has been notified in writing, (iii) (A) Purchaser shall cause an environmental consulting firm selected by Purchaser but reasonably acceptable to Seller (the "Environmental Auditor") to conduct, within ninety (90) days following the Effective Date, a Phase I environmental site assessment of, and to prepare a written report with respect to, the Project and the Project Site (the "Phase I Assessment"), (B) Seller shall provide the Environmental Auditor with reasonable access to the Project and the Project Site for such purpose, and (C) Purchaser shall promptly deliver to Seller a copy of the final written report associated with the Phase I Assessment upon

completion thereof, and (iv) neither Purchaser nor its Representatives shall collect or analyze any environmental samples (including building materials, indoor and outdoor air, surface and ground water, and surface and subsurface soils), without the prior written authorization of Seller. Purchaser agrees to indemnify and hold harmless, release, and defend Seller and its Affiliates and Representatives from and against any and all Losses arising out of, resulting from or relating to, in whole or in part, the acts or omissions of Purchaser or its Representatives arising under this Section 5.01 in connection with Purchaser's inspection of the Project, the Project Site, the Purchased Assets and the Books and Records, including claims for personal injuries, property damage, and reasonable attorneys' fees and expenses.

Section 5.02 Conduct of Business; Integration. (a) From the date hereof until the Closing, Seller shall conduct the Business and operate and maintain the Project only in the ordinary course consistent with past practice, provided that, at all times between the Effective Date until Closing, Seller shall operate and maintain the Project in accordance with Good Utility Practices for operation, maintenance and compliance including, without limitation, by taking the actions set forth in Section 5.02(a) of the Purchaser Disclosure Schedule within the timeframes provided for therein. Without limiting the generality of the foregoing, Seller will use commercially reasonable efforts to (i) preserve intact the present business organization and reputation of the Business in all material respects; (ii) maintain the Purchased Assets in substantially similar condition as they were on the Effective Date, ordinary wear and tear excepted; and (iii) maintain the goodwill of key Persons with whom the Company otherwise has significant business relationships with respect to the Purchased Assets.

(b) Following FERC Approval, Seller and Purchaser shall reasonably cooperate to facilitate a successful transition of the Project from Seller to Purchaser and permit the timely completion of critical integration activities. Such activities shall include, without limitation, the actions set forth in Section 5.02(b) of the Purchaser Disclosure Schedule. Purchaser's indemnity set forth in the last sentence of Section 5.01 shall also be applicable to all such integration activities undertaken.

(c) To ensure that the Project and the APEC are completely independent of each other prior to the Closing, prior to June 1, 2015, Seller shall develop and provide Purchaser with a comprehensive plan (the "Separation Plan") to eliminate any interdependencies which are required to be set forth on Section 3.20(b) of the Seller Disclosure Schedule prior to Closing in a manner which is acceptable to Purchaser. Seller shall be responsible for all costs associated with the implementation of such Separation Plan.

Section 5.03 Certain Restrictions. From the date hereof until the Closing, Seller shall refrain, and shall cause its Affiliates to refrain, from taking any of the following actions, except (i) with respect to those matters set forth in Section 5.03 of the Seller Disclosure Schedule, (ii) as expressly permitted or required by this Agreement, including, but not limited to, the provisions for proper operations, maintenance, compliance and preservation of the Purchased Assets, (iii) with Purchaser's prior consent (which shall not be unreasonably withheld, conditioned or delayed) or (iv) as required by Law:

(a) amending Seller's certificate of formation or its limited liability company agreement, in any manner which could materially adversely impact Seller's ability to consummate the transactions contemplated by this Agreement;

(b) acquiring, disposing or removing from the Project Site any asset of the Company (other than Inventory) with a value in excess of [redacted] which would be included in the Purchased Assets or the Project Site, or incurring any Liens on the Purchased Assets, other than Permitted Liens;

(c) entering into or amending in any material respect, any Company Contract (or any Contract that if in existence on the date hereof would have been required to be disclosed on Section 3.13 of the Seller Disclosure Schedule) other than an Excluded Contract;

(d) incurring, assuming, guaranteeing or modifying any Indebtedness of the Company, except as would upon or after the Closing constitute an Excluded Liability;

(e) except as set forth in Section 5.03(e) of the Seller Disclosure Schedule, making capital expenditures or commitments with respect to the Business, the Purchased Assets, the Project and the Project Site for additions to property, plant or equipment constituting capital assets in an aggregate amount exceeding [redacted];

(f) failing to maintain insurance coverage with respect to the Business, the Purchased Assets, the Project and the Project Site substantially equivalent to (i) the insurance coverage currently maintained, or (ii) if such coverage is not available on commercially reasonable terms, the insurance coverage maintained with respect to other similarly-situated power generation facilities owned by Calpine or any of its Affiliates;

(g) failing to use commercially reasonable efforts to maintain the properties and assets included in the Purchased Assets in at least the same condition as they were on the Effective Date, subject to reasonable wear and tear;

(h) voluntarily taking any action constituting a failure to comply with any material Permit in any material respect required for the conduct of the Business as currently conducted or the ownership and use of the Purchased Assets;

(i) hiring any employees to provide services at or for the Project other than to fill vacancies, [redacted]

(j) establishing, amending or terminating any compensation or benefit plan, program, policy, practice, arrangement or agreement on behalf of any Facility Employee or officer or director of the Company, or increase the compensation or benefits of any Facility Employee or officer or director of the Company except in the ordinary course of business consistent with past practice;

(k) except as required by GAAP, making any change in any method of accounting or auditing practice of Seller;

(l) acquiring, selling or transferring any specialty tooling except that Seller may consume and replenish specialty tooling in the ordinary course of business consistent with past practice;

(m) amending any property Tax Return for property Taxes relating to, imposed on, or attributable to the Purchased Assets;

(n) terminating any Contract relating to the maintenance, support or escrow of any Project Software that is a Purchased Asset, unless such Contract is replaced, or refusing to install any update, new release, new version, upgrade, patch, error correction or other modification of any Project Software that is a Purchased Asset to which Seller is entitled (of which Seller is aware) to receive pursuant to any such Contract, except if Seller (or its parent entities) does not adopt such update, release, version, upgrade, patch, error correction or other modification for the applicable Calpine facilities generally; or

(o) agreeing, authorizing or committing to do or engage in any of the foregoing.

Notwithstanding Section 5.03, or any other provision herein, (x) Seller may take commercially reasonable actions with respect to emergency situations; provided, that Seller shall act in accordance with Good Utility Practice and promptly notify Purchaser of the taking of such actions, and (y) Seller may remove any and all Inventory from the Project and the Project Site at any time prior to the Closing, and during the ten Business Days immediately after the Closing.

Furthermore, if any Liens (other than Permitted Liens) are incurred on the Purchased Assets by actions of Seller during the period from the date hereof until Closing, the Seller shall cure any such Liens which are monetary title and survey defects, and shall use commercially reasonable efforts to cure any other Liens (other than Permitted Liens), in each case prior to the Closing.

Section 5.04 Governmental Approvals.

(a) Subject to the terms and conditions of this Agreement and applicable Law, each party shall use its reasonable commercial efforts to take, or cause to be taken, all actions and do, or cause to be done, all things necessary, proper or advisable to obtain as promptly as reasonably practicable all necessary or appropriate waivers, consents, approvals or authorizations of Governmental or Regulatory Authorities, including without limitation with respect to the FERC, FPSC and HSR Act, and to satisfy all other conditions required in order to consummate the transactions contemplated by this Agreement.

(b) In addition to the foregoing, (i) Purchaser, on the one hand, and Seller, on the other hand, shall, in accordance with Section 5.04(c) hereof, file no later than January 30, 2015, any application, form or report required for FERC approval of the transaction contemplated by this Agreement (the initial draft of which shall be prepared by Seller and made available for review by Purchaser by no later than January 15, 2015), and Purchaser shall use its reasonable best efforts to diligently pursue all necessary and appropriate waivers, consents, approvals or authorizations of FERC; provided, however, that nothing in this Agreement shall require the Purchaser to [redacted]

[redacted] (ii) Purchaser shall file no later than January 30, 2015, any application or petition before the FPSC seeking all necessary approvals from the FPSC to consummate the transactions contemplated herein, which application shall (A) be drafted by Purchaser, and Seller shall have at least seven (7) Business Days to review and comment on such draft prior to its filing and (B) either continue to proceed under the Existing FPSC Docket or seek to proceed under a new FPSC filing docket, (iii) Purchaser, on the one hand, and Seller, on the other hand, shall file notification and report forms required pursuant to the HSR Act with the Antitrust Division of the Department of Justice (the "DOJ") and the Federal Trade Commission ("FTC") no later than January 30, 2015 (the "Initial HSR"), requesting early termination of the waiting period thereunder, and Purchaser, on the one hand, and Seller, on the other hand, shall use its commercially reasonable efforts to diligently pursue all necessary clearances, consents, approvals or authorizations of the DOJ and FTC, as applicable; provided, however, that nothing in this Agreement shall require the Purchaser to [redacted], and (iv) Purchaser, on the one hand, and Seller, on the other hand, shall file no later than March 31, 2016, any other form or report required by any Governmental or Regulatory Authority relating to antitrust, competition, trade or energy regulation matters. Purchaser and Seller shall make any additional filings under the HSR Act, and observe waiting periods accordingly, as are necessary to consummate the transaction. Each of the parties shall request expedited treatment of any such filings. Purchaser and Seller shall (i) respond as promptly as practicable to any inquiries or requests received from any Governmental or Regulatory Authority for additional information or documentation and (ii) not enter into any agreement with any Governmental or Regulatory Authority not to consummate the transactions contemplated by this Agreement, except with the prior consent of the other party (which shall not be unreasonably withheld, delayed or conditioned). Each party shall (i) promptly notify the other party of any material written communication to that party from any Governmental or Regulatory Authority and, subject to applicable Law and execution of an appropriate joint defense arrangement, permit the other party or its counsel to review in advance any proposed written communication to any of the foregoing, (ii) not agree to participate in any substantive meeting or discussion with any Governmental or Regulatory Authority in respect of any filings, investigation or inquiry concerning this Agreement or the transactions contemplated hereby unless it consults with the other party in advance and, to the extent permitted by such Governmental or Regulatory Authority, gives the other party the opportunity to attend and participate thereat, and (iii) subject to applicable Law and execution of an appropriate joint defense arrangement, furnish the other party with copies of all material correspondence, filings, and communications (and memoranda setting forth the substance thereof) between them and their Affiliates and their respective Representatives on the one hand, and any Governmental or Regulatory Authority or members of their respective staffs on the other hand, with respect to this Agreement and the transactions contemplated hereby.

(c) The parties shall cooperate in the preparation of, and each have the right to approve, not to be unreasonably withheld, any application, form or report required for FERC approval of the transaction contemplated by this Agreement that must be submitted jointly by Seller and Purchaser.

(d) Seller shall reasonably cooperate in the obtaining of the necessary approvals from the FPSC to consummate the transactions contemplated herein, including preparation for and attendance at any hearings before the FPSC.

Section 5.05 Tax Matters.

(a) All real property Taxes, personal property Taxes and similar ad valorem obligations levied with respect to the Purchased Assets for an Overlap Period (collectively, the "Apportioned Obligations") shall be apportioned between Seller and Purchaser based on the number of days of such taxable period included in the Pre-Closing Period and the number of days of such taxable period after the Closing Date (such portion of such taxable period, the "Post-Closing Tax Period"). Seller shall be liable for the proportionate amount of such Taxes that is attributable to the Pre-Closing Period, and Purchaser shall be liable for the proportionate amount of such Taxes that is attributable to the Post-Closing Tax Period. The Apportioned Obligations will be apportioned at Closing pursuant to this Section 5.05(a) based on the actual amounts of the Apportioned Obligations for the Overlap Period if known at Closing. If the actual amounts of the Apportioned Obligations are not known at the Closing, then the Apportioned Obligations shall be apportioned at Closing based on an estimated amount equal to the actual amount of Apportioned Obligations for the immediately preceding period.

(b) If the Apportioned Obligations are apportioned at Closing based on an estimate of the Apportioned Obligations pursuant to Section 5.05(a), then promptly following the filing of the Tax Return relating to such Apportioned Obligations (or, if no Tax Return relates to such Apportioned Obligation, the payment by Purchaser of the actual amount of Apportioned Obligations for the applicable Overlap Period), Purchaser shall provide Seller with notice of the actual amount of such Apportioned Obligations and, if applicable, Seller's actual share of such Apportioned Obligations pursuant to Section 5.05(a). Purchaser shall reimburse Seller if and to the extent that the amount of Apportioned Obligations apportioned to Seller at Closing exceeds the actual amount of Seller's share of the Apportioned Obligations. Seller shall reimburse Purchaser if and to the extent that the amount of Apportioned Obligations apportioned to Purchaser at Closing exceeds the actual amount of Purchaser's share of the Apportioned Obligations. Any payment required under this Section 5.05(b) shall be paid within ten (10) days of Seller's receipt of Purchaser's notice of the actual amount of the Apportioned Obligations for the Overlap Period.

(c) Any Tax Return filed after the Closing with respect to Taxes of, or with respect to an Overlap Period shall be prepared by Purchaser in accordance with past practices relating to the Purchased Assets unless otherwise required by Law, and submitted (with copies of any relevant schedules, work papers, and other documentation then available) to Seller for its review and comment not less than twenty (20) days prior to the due date for the filing of such Tax Return (taking into account any valid extensions). Seller shall have the option of providing to Purchaser, at any valid time at least seven (7) days prior to the date such Tax Return is due to be filed (taking into account any valid extensions), written comments to the Overlap Period Tax Return, Purchaser shall consider such comments and the Parties shall use their reasonable efforts to resolve any disputed items. If the Parties cannot come to mutual agreement on any such Tax Return, the matter shall be resolved in accordance with substantially identical procedures as set forth for the resolution of disputes in Section 2.08; provided that if any disputes have not been

resolved by the due date for filing a Tax Return for the Overlap Period giving effect to all available valid extensions, Purchaser shall have the right to file any such Tax Return in a manner determined by the Purchaser, and the Tax Return will be amended if and to the extent necessary to reflect the resolution of any disputed item.

(d) Following the Closing, Seller shall not make any Tax election, amend any Tax Return, or respond to any audit or inquiry by a taxing authority that could reasonably be expected to materially adversely affect the Tax liability of Purchaser or any of its Affiliates without the prior written consent of Purchaser, which consent shall not be unreasonably withheld or delayed.

(e) If Seller does not deliver to Purchaser the certification required by Section 6.03(b), Purchaser shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement (including the Purchase Price) such amount as it is required pursuant to Section 1445 of the Code to deduct and withhold with respect to the making of such payment.

(f) Notwithstanding anything in this Agreement to the contrary, any proceeding with a Governmental or Regulatory Authority relating to any Taxes attributable to the Purchased Assets which are described in Section 5.05(a) shall be controlled at all stages by Purchaser; provided, however, that Purchaser shall permit Seller to participate in such proceedings, negotiations or defense at any time at its own expense and Purchaser shall not settle or otherwise compromise any such proceeding without the prior written consent of Seller, which shall not be unreasonably withheld, conditioned or delayed.

Section 5.06 Changes in Condition of Assets. (a) [redacted]

[redacted]

(b) (i)

[redacted]

(ii)

[redacted]

[redacted]

(iii) [redacted]

[redacted]

(iv) [redacted]

(c) [redacted]

Section 5.07 Employees.

(a) Subject to this Section 5.07, Purchaser shall extend a written offer of employment, effective as of the Closing Date and contingent on the Closing actually occurring, [redacted]

(b) Each Facility Employee who accepts such offer of employment and commences employment with Purchaser or an Affiliate on the Closing Date is referred to herein as a "Hired Employee" and all such Facility Employees collectively as the "Hired Employees".

(c) Purchaser shall be solely responsible for any and all severance or termination pay expenses which arise in connection with the termination of employment of any Hired Employee by Purchaser after the Closing Date.

(d) Purchaser shall recognize for all purposes, other than benefit accrual under any defined benefit pension plan and other than for all purposes under any post-retirement healthcare plan, under Purchaser's and its Affiliates' policies and employee benefit plans (including paid time off and severance) the service of any Hired Employee with the Operator and/or any of its Affiliates (and each predecessor respectively thereof) prior to the Closing Date, except to the extent that recognition of such service would result in duplication of benefits.

(e) The Operator or its Affiliates shall retain responsibility for the payment of any employee benefits or entitlement accrued through the Closing Date, including severance or termination pay, bonuses, accrued vacation, sick or holiday pay, to any Facility Employee or pursuant to any Benefit Plan as a result of or in connection with the consummation of the transactions contemplated hereby.

(f) Notwithstanding the foregoing, nothing contained in this Agreement shall be deemed or construed to (i) give rise to any rights, claims, benefits or causes of action to a Facility Employee or representative thereof or make any Facility Employee or representative thereof a third party beneficiary hereof, (ii) be treated as an amendment or other modification of any employee benefit plan, or (iii) prevent, restrict or limit each of Seller, the Operator, any Affiliate of Seller or the Operator, Purchaser or any Affiliate of Purchaser, following the Closing Date, from modifying or terminating any of its benefit plans, programs or policies from time to time as it may deem appropriate, subject only to compliance with the express provisions of this Section 5.07.

Section 5.08 Insurance. Purchaser acknowledges that, effective upon the Closing, Seller shall terminate or modify the Project Insurance Policies to exclude coverage of the Business, the Purchased Assets, the Project and the Project Site from the Project Insurance Policies or any other policies of insurance maintained by Seller.

Section 5.09 Transfer Taxes. All transfer Taxes, including documentary, sales, use, stamp, registration, filing, recording, permit, license, authorization, controlling interest transfer and other similar Taxes and fees (including any penalties and interest) ("Transfer Taxes") incurred in connection with this Agreement and the transactions contemplated hereby, if any, shall be shared equally by Purchaser and Seller when due, and Purchaser and Seller shall file all necessary Tax Returns and other documentation with respect to any such Transfer Taxes, and, if required by applicable Law, Purchaser and Seller shall, as applicable, and shall cause their respective Affiliates to, join in the execution of any such Tax Returns and other documentation and shall cooperate with each other to take such commercially reasonable actions as will minimize or reduce the amount of such Taxes.

Section 5.10 Release of Credit Support.

(a) Prior to the Closing, Purchaser shall use commercially reasonable efforts to effect the full and unconditional release of Seller and its Affiliates from all guarantees, letters of credit and other credit support posted on behalf of Seller or an Affiliate of Seller and relating to the Project or the Purchased Assets set forth in Section 5.10 of the Seller Disclosure Schedule (the "Credit Support Obligations"), [redacted]

(b) Within ninety (90) days following the Closing, Purchaser shall effect the full and unconditional release of Seller and its Affiliate from the Credit Support Obligations.

Section 5.11 [redacted]

(a) [redacted]

(b) [redacted]

(c) [redacted]

Section 5.12 Reports; Financial Statements. Seller will furnish to Purchaser (a) promptly after available, copies of all Governmental or Regulatory Approvals or Permits filed with any Governmental or Regulatory Authority after the date hereof, (b) promptly after available (but in no event later than forty-five (45) days following the relevant period), quarterly unaudited balance sheets of the Seller, and (c) promptly after asserted, a summary of any material claims asserted by Seller pursuant to any Project Insurance Policy after the Effective Date. Each of the financial statements delivered pursuant to this Section 5.12 shall be prepared in conformance with the presentation and delivery requirements contained in Section 3.05. Each of the financial statements delivered pursuant to this Section 5.12 shall be accompanied by a certificate of an authorized financial officer of Seller to the effect that such financial statements are prepared in conformance with the presentation requirements set forth in Section 3.05.

Section 5.13 Notification of Certain Matters. Each party hereto shall give prompt notice to the other party hereto after becoming aware of (a) the occurrence, or failure to occur, of any event that causes, or would be likely to cause, any representation or warranty of the notifying party contained in this Agreement to be untrue or inaccurate in any material respect at any time

from the Effective Date to the Closing Date and (b) any failure of the notifying party to comply with or satisfy, in any material respect, any covenant, condition or agreement to be complied with or satisfied by it under this Agreement. No such notification shall affect the representations or warranties of the parties or the conditions to their respective obligations hereunder.

Section 5.14 Seller's Marks. Within thirty (30) days following the Closing, Purchaser shall, and shall cause each of its Affiliates to, cease using the word "Calpine" and any word or expression similar thereto or constituting an abbreviation or extension thereof (the "Seller's Marks"), including eliminating the Seller's Marks from all the Purchased Assets and the disposing of any unused stationery and literature of Calpine or Seller related to the Purchased Assets, and thereafter, Purchaser shall not, and shall cause its Affiliates and the Project not to, use the Seller's Marks or any logos, trademarks, trade names, patents or other Intellectual Property rights belonging to Seller or any of its Affiliates, or which Seller or any of its Affiliates have the right to use, and Purchaser acknowledges that it, its Affiliates, and the Project have no rights whatsoever to use such Intellectual Property.

ARTICLE VI

CONDITIONS TO OBLIGATIONS OF PURCHASER

The obligation of Purchaser to consummate the transactions described in Article II are subject to the fulfillment, at or before the Closing, of each of the following conditions (all or any of which may be waived in writing in whole or in part by Purchaser in its sole discretion):

Section 6.01 Representations and Warranties. The representations and warranties of Seller contained in Article III of this Agreement (other than the Fundamental Representations of Seller contained therein and the representation contained in Section 3.07(b)) shall be true and correct as of the Closing Date as though such representations and warranties were made on and as of the Closing Date (or, to the extent such representations and warranties expressly relate to an earlier date, on and as of such earlier date), except where the failure of such representations and warranties to be true and correct (in each case disregarding all qualifications and exceptions contained therein relating to materiality or Material Adverse Effect) would not reasonably be expected to have a Material Adverse Effect; and the Fundamental Representations made by Seller and the representation contained in Section 3.07(b) shall be true and correct in all respects as of the Closing Date (except to the extent such Fundamental Representations expressly relate to an earlier date, in which case such earlier date).

Section 6.02 Performance. Seller shall have performed and complied in all material respects with the agreements, covenants and obligations required by this Agreement to be so performed or complied with by Seller at or before the Closing.

Section 6.03 Officers' Certificates. Seller shall have delivered to Purchaser (a) an officer's certificate, dated the Closing Date and executed in the name and on behalf of Seller, certifying that all of the conditions set forth in Sections 6.01 and 6.02 have been satisfied and (b) a certificate, dated the Closing Date and executed in the name of and on behalf of Calpine Corporation, stating that Calpine Corporation is not a "foreign" person within the meaning of

Section 1445 of the Code, which certificate shall set forth all information required by, and shall otherwise be executed in accordance with, Treasury Regulation Section 1.1445-2(b)(2).

Section 6.04 Orders and Laws. There shall not be in effect on the Closing Date any Order or Law restraining, enjoining or otherwise prohibiting or making illegal the consummation of the transactions contemplated by this Agreement.

Section 6.05 Governmental or Regulatory Approvals. All Governmental or Regulatory Approvals set forth in Section 6.05 of the Purchaser Disclosure Schedule shall have been obtained, made or given, and shall be in full force and effect.

Section 6.06 Instruments of Transfer. At or prior to the Closing, Seller shall have executed and delivered to Purchaser (i) the Bill of Sale, (ii) the Assignment and Assumption Agreement, (iii) the Deed, with a legal description derived from the Survey, and (iv) and such other documentation and instruments of transfer as shall be reasonably required. At or prior to the Closing, Calpine Energy Services, L.P. shall have executed and delivered to Purchaser the Assignment and Assumption Agreement (CES).

Section 6.07 Third-Party Consents. The consents (or waivers in lieu thereof) set forth in Section 6.07 of the Purchaser Disclosure Schedule shall have been obtained, made or given, and shall be in full force and effect

Section 6.08 No Material Adverse Effect. Since the date hereof, there shall not have occurred and be continuing a Material Adverse Effect.

ARTICLE VII

CONDITIONS TO OBLIGATIONS OF SELLER

The obligation of Seller to consummate the transactions described in Article II are subject to the fulfillment, at or before the Closing, of each of the following conditions (all or any of which may be waived in writing in whole or in part by Seller in its sole discretion):

Section 7.01 Representations and Warranties. The representations and warranties of Purchaser contained in Article IV of this Agreement (other than the Fundamental Representations of Purchaser contained therein) shall be true and correct as of the Closing Date as though such representations and warranties were made on and as of the Closing Date (or, to the extent such representations and warranties expressly relate to an earlier date, on and as of such earlier date), except for failures of the representations and warranties to be true and correct which do not have material adverse effect on Purchaser's ability to perform its obligations hereunder; and the Fundamental Representations made by Purchaser shall be true and correct in all respects as of the Closing Date (except to the extent such Fundamental Representations expressly relate to an earlier date, in which case such earlier date).

Section 7.02 Performance. Purchaser shall have performed and complied in all material respects with the agreements, covenants and obligations required by this Agreement to be performed or complied with by Purchaser at or before the Closing.

Section 7.03 Officer's Certificates. Purchaser shall have delivered to Seller an officer's certificate, dated the Closing Date and executed in the name and on behalf of Purchaser, certifying that all of the conditions set forth in Sections 7.01 and 7.02 have been satisfied.

Section 7.04 Orders and Laws. There shall not be in effect on the Closing Date any Order or Law restraining, enjoining or otherwise prohibiting or making illegal the consummation of any of the transactions contemplated by this Agreement.

Section 7.05 Governmental or Regulatory Approvals. All Governmental or Regulatory Approvals set forth in Section 7.05 of the Seller Disclosure Schedule shall have been obtained, made or given, and shall be in full force and effect.

Section 7.06 Third-Party Consents. The consents (or waivers in lieu thereof) set forth in Section 7.06 of the Seller Disclosure Schedule shall have been obtained, made or given, and shall be in full force and effect.

Section 7.07 Instruments of Transfer. At or prior to the Closing, Purchaser shall have executed and delivered to Seller the Assignment and Assumption Agreement, the Assignment and Assumption (CES) and such other documentation and instruments of transfer as shall be reasonably required.

Section 7.08 Release of Credit Support. Purchaser shall have complied with its obligations under Section 5.10(a).

ARTICLE VIII

INDEMNIFICATION; NO OTHER REPRESENTATIONS

Section 8.01 Survival. The representations, warranties, covenants and agreements of Purchaser and Seller contained in this Agreement [redacted] and no claims shall be made thereafter with respect to any breach thereof or indemnification for any breach thereof, except for (i) the representations and warranties set forth in Section 3.14 (Taxes), [redacted] (ii) the representations and warranties of Seller set forth in Section 3.15 (Employee Matters) and Section 3.17 (Environmental Matters), which [redacted]; (iii) the representations and warranties of Seller set forth in Section 3.01 (Legal Existence) and Section 3.02 (Authority) and Section 3.19 (Brokers), which [redacted] (iv) the representations and warranties of Seller set forth in Section 3.03 (No Conflicts) and Section 3.06 (No Undisclosed Liabilities) which [redacted] (v) the representations and warranties of Seller set forth in the second sentence of Section 3.10 (Real Property), the first sentence of Section 3.11 (Personal Property) and the first sentence of Section 3.12 (Intellectual Property), which [redacted] (the "Property Reps"), (vi) the representations and warranties of Purchaser set forth in Section 4.01 (Legal Existence), Section 4.02 (Authority), and Section 4.07 (Brokers) which [redacted], (vii) the representations and warranties of Purchaser set forth in Section 4.03 (No Conflicts), which [redacted] (the items in clauses (iii) and (vi) collectively, the "Fundamental

Representations"); (viii) claims which are asserted in good faith prior to the end of the applicable periods set forth in clauses (i) through (vii) immediately above, which [redacted]; and (ix) covenants and agreements (including obligations to indemnify) that are to be performed in whole or in part following the Closing, which [redacted]

Section 8.02 Indemnification.

(a) Subject to Sections 8.01 and 8.02(b), and the other limitations to indemnification set forth in this Article VIII, from and after the Closing:

(i) Seller shall indemnify, defend and hold harmless Purchaser and its respective Affiliates and Representatives (collectively, the "Purchaser Indemnified Parties") from and against all Losses actually incurred or suffered by the Purchaser Indemnified Parties arising out of, resulting from or relating to: (A) any breach of any representation or warranty of Seller contained in this Agreement or any Ancillary Agreement to which Seller is a party as of the Closing as if made on the Closing Date (except to the extent expressly made as of an earlier date); (B) any breach of any covenant or agreement of Seller contained in this Agreement or any Ancillary Agreement to which Seller is a party; and (C) the Excluded Liabilities (without duplication of amount paid by Seller to Purchaser in accordance with Section 5.05(a) or Section 5.05(b)).

(ii) Purchaser shall indemnify, defend and hold harmless Seller and its Affiliates and Representatives (collectively, the "Seller Indemnified Parties") from and against all Losses actually incurred or suffered by the Seller Indemnified Parties arising out of, resulting from or relating to: (A) any breach of any representation or warranty of Purchasers contained in this Agreement or any Ancillary Agreement to which Purchaser is a party as of the Closing as if made on the Closing Date (except to the extent expressly made as of an earlier date); (B) any breach of any covenant or agreement of Purchaser contained in this Agreement or any Ancillary Agreement to which Purchaser is a party; and (C) the Assumed Liabilities.

(b) Notwithstanding anything in this Agreement to the contrary, except in the case of any claim based upon (i) fraud, intentional misrepresentation or criminal activity or (ii) the breach of any Property Rep, Section 3.14 (Taxes) or any Fundamental Representation, in each case, which shall not be subject to limitations set forth in this Section 8.02(b) (with the exception of the last sentence in Section 8.02(b)), neither party shall have any liability under Section 8.02(a)(i)(A) and Section 8.02(a)(ii)(A) (x) if the Persons listed in Section 1.01(a) of the Purchaser Disclosure Schedule (in the case of liability under Section 8.02(a)(i)(A)) or the Persons listed in Section 1.01(b) of the Seller Disclosure Schedule (in the case of liability under Section 8.02(a)(ii)(A)) had actual and direct knowledge of such breach or of all facts material to such breach, except in the case of liability under Section 8.02(a)(i)(A), for those matters set forth on Section 8.02(b) of the Purchaser Disclosure Schedule; and (y) until the aggregate amount of all such Losses exceeding such amount incurred by the Purchaser Indemnified Parties or the Seller Indemnified Parties, as applicable [redacted] (the "Deductible Amount"), in which event the indemnifying party shall be liable for Losses only to the extent they are in excess of the Deductible Amount, and in no event shall the aggregate liability of the

indemnifying party for claims made pursuant to Section 8.02(a)(i)(A) or Section 8.02(a)(ii)(A), as the case may be (other than the Fundamental Representations), exceed [redacted]. Notwithstanding anything herein to the contrary, neither Purchaser nor Seller shall be liable under this Agreement to the other party for aggregate Losses in excess of the Purchase Price.

(c) Notwithstanding anything in this Agreement to the contrary, there shall be no indemnification pursuant to this Agreement by any indemnifying party hereunder for any punitive, special, indirect, exemplary, incidental, consequential or similar damages (including any damages on account of lost profits, loss of revenue, loss of production or diminution in value (based on multiple of earnings or otherwise) or other damages attributable to business interruption), whether by statute, in tort or under contract, under any indemnity provision or otherwise, except in connection with a Third-Party Claim.

(d) The parties have negotiated the limitations set forth in Section 8.02(b) in part to avoid disputes concerning the meaning of materiality qualifiers such as "Material Adverse Effect", "material", "materially", "in all material respects" and other similar qualifiers. Accordingly, for purposes of this Article VIII, any such materiality qualifier contained in any representation or warranty or in the definition of any defined term used therein (except for the representation in Section 3.07(b)) shall be ignored in determining whether there has been a breach of or inaccuracy in a representation or warranty and in measuring the corresponding damages.

Section 8.03 Duty to Mitigate. A party that becomes aware of a Loss for which it may seek indemnification under this Article VIII shall use commercially reasonable efforts to mitigate such Loss, including taking any actions reasonably requested by the other party, and such other party shall not be liable for any Loss to the extent that it is attributable to the failure of the party seeking indemnification to comply with this Section 8.03.

Section 8.04 Exclusive Remedy; Reduction of Benefit.

(a) Purchaser and Seller acknowledge and agree that from and after the Closing, except in the case of fraud or intentional misrepresentation, (i) the indemnification provisions in this Article VIII shall be the sole and exclusive remedy of the Purchaser Indemnified Parties and the Seller Indemnified Parties with respect to any breach of, or cause of action arising under this Agreement and the Ancillary Agreements (other than the Parent Guaranty and the Calpine Guaranty) or any claims relating to or arising under Environmental Law, including common law and statutory remedies (including, remedies under CERCLA and any other Environmental Law); and (ii) Purchaser expressly and knowingly releases and waives any right to seek any form of recourse other than the indemnification provisions in this Article VIII against Seller or its Affiliates with respect to claims relating to or arising under Environmental Laws, including common law and statutory remedies.

(b) Any obligation of Purchaser to indemnify a Seller Indemnified Party or of Seller to indemnify a Purchaser Indemnified Party shall be reduced to the extent of the cash paid to the applicable indemnified party (net of any costs incurred to recover such amount) pursuant to (y) a warranty or indemnification from a third party or (z) insurance.

(c) No Losses may be claimed under Section 8.02 by any Purchaser Indemnified Party or Seller Indemnified Party, as the case may be, to the extent such Losses are included in the calculation of any adjustment to the Purchase Price as [redacted].

(d) It is the express intention of the parties that the indemnification provided for in this Article VIII shall apply to direct claims between the parties for a breach of this Agreement and the Ancillary Agreements (whether or not involving a third party).

Section 8.05 Procedure With Respect to Third-Party Claims.

(a) No claim may be asserted pursuant to this Article VIII for breach of any representation, warranty, covenant or agreement contained herein unless written notice of such claim is delivered by the party seeking indemnification on or prior to the date on which the representation, warranty, covenant or agreement on which such claim is based ceases to survive as set forth in this Article VIII.

(b) If any Purchaser Indemnified Party or Seller Indemnified Party becomes subject to a pending or threatened claim of a third party (a "Third-Party Claim") and such Person (the "Claiming Party") believes it has a claim for indemnification against Purchaser or Seller, as applicable (the "Responding Party"), then the Claiming Party shall deliver to the Responding Party with reasonable promptness written notice of such Third-Party Claim. The Responding Party shall notify the Claiming Party as soon as practicable whether the Responding Party desires to defend the Claiming Party against such Third-Party Claim. The failure of the Claiming Party to so notify the Responding Party shall not relieve the Responding Party of liability hereunder; provided, however, that if the defense of such Third-Party Claim is prejudiced by the failure to give such notice, any Third Party Claim shall be reduced by the damages resulting from such Claiming Party's delay or failure to provide notice. Within thirty (30) days after receipt of any notice pursuant to this Section 8.05(b), the Responding Party shall notify the Claiming Party in writing that it desires to defend the Third-Party Claim pursuant to this Section 8.05(b) and acknowledge its obligations to indemnify hereunder. Upon giving such notice, the Responding Party shall have control of such defense and proceedings, including any settlement thereof.

(c) If the Responding Party notifies the Claiming Party that it desires to defend the Third-Party Claim pursuant to Section 8.05(b), then the Responding Party shall work diligently to defend the Third-Party Claim with counsel reasonably acceptable to the Claiming Party and shall not enter into any settlement or consent to the entry of any Order (i) that does not include as a term thereof the giving by each claimant or plaintiff to the Claiming Party a release from all liability in respect of such Third-Party Claim, (ii) that provides for any relief other than the payment of monetary damages as to which the Claiming Party shall be paid in full or (iii) in the reasonable judgment of the Claiming Party, is likely to establish a precedential custom or practice or result in an outcome that is materially adverse to the continuing business interests of the Claiming Party; provided, however, that if requested by the Responding Party, the Claiming Party shall, at the sole cost and expense of the Responding Party, reasonably cooperate with the Responding Party and its counsel in contesting any Third-Party Claim that the Responding Party elects to contest. The Claiming Party may elect to participate in such proceedings, negotiations or defense at any time at its own expense; provided, however, that the Responding Party shall pay the reasonable attorneys' fees of the Claiming Party if (i) the employment of separate counsel

shall have been authorized in writing by the Responding Party in connection with the defense of such Third-Party Claim, (iii) there are legal defenses available to the Claiming Party that are different from or additional to those available to the Responding Party or (iii) the Claiming Party's counsel shall have advised the Claiming Party in writing, with a copy delivered to the Responding Party, that there is a conflict of interest that could make it inappropriate under applicable standards of professional conduct for the Responding Party and the Claiming Party to have common counsel.

(d) Until the Responding Party notifies the Claiming Party that the Responding Party desires to defend the Third-Party Claim pursuant to Section 8.05(b), the Claiming Party shall (upon reasonable prior notice to the Responding Party) have the right to undertake the defense of such Third-Party Claim, with counsel chosen by the Claiming Party; provided, however, that the Responding Party shall reimburse the Claiming Party for the costs of defending against such Third-Party Claim (including reasonable attorneys' fees and expenses) and shall remain otherwise responsible for any liability with respect to amounts arising from or related to such Third-Party Claim, in both cases to the extent it is ultimately determined that such Responding Party is liable with respect to such Third-Party Claim for a breach under this Agreement; and provided, further, that the Claiming Party shall not enter into settlement of any such Third-Party Claim without the prior written consent of the Responding Party which shall not be unreasonably withheld. The Responding Party may elect to participate in such proceedings, negotiations or defense at any time at its own expense.

(e) Sections 8.05(a) through (d) apply only to indemnification relating to Third Party Claims. A party to this Agreement may assert an indemnity claim not related to a Third Party Claim by providing notice to the other party within the applicable time periods set forth in Section 8.01.

Section 8.06 Effect of Investigation. Subject to Section 8.02(b)(x), the representations, warranties and covenants of the indemnifying party, and the indemnified party's right to indemnification with respect thereto, shall not be affected or deemed waived by reason of any investigation made by or on behalf of the indemnified party (including by any of its Representatives) or by reason of the fact that the indemnified party or any of its Representatives should have known that any such representation or warranty is, was or might be inaccurate or by reason of the indemnified party's waiver of any condition set forth in Article VI or Article VII, as the case may be.

Section 8.07 Adjustment to Purchase Price. [redacted]

Section 8.08 Release of Indemnity Escrow Funds. The Indemnity Escrow Fund will be released pursuant to the terms of the Escrow Agreement as follows:

(a) In the event that, prior to the date of the expiration of the Indemnity Escrow Period, a Purchaser Indemnified Party is entitled to receive payments under (i) any mutual agreement between the parties or (ii) any final Order, in any case, regarding claims for Losses made by such Purchaser Indemnified Party pursuant to Section 8.02(a)(i), then Purchaser and Seller will promptly execute a joint written instruction to the Escrow Agent directing the

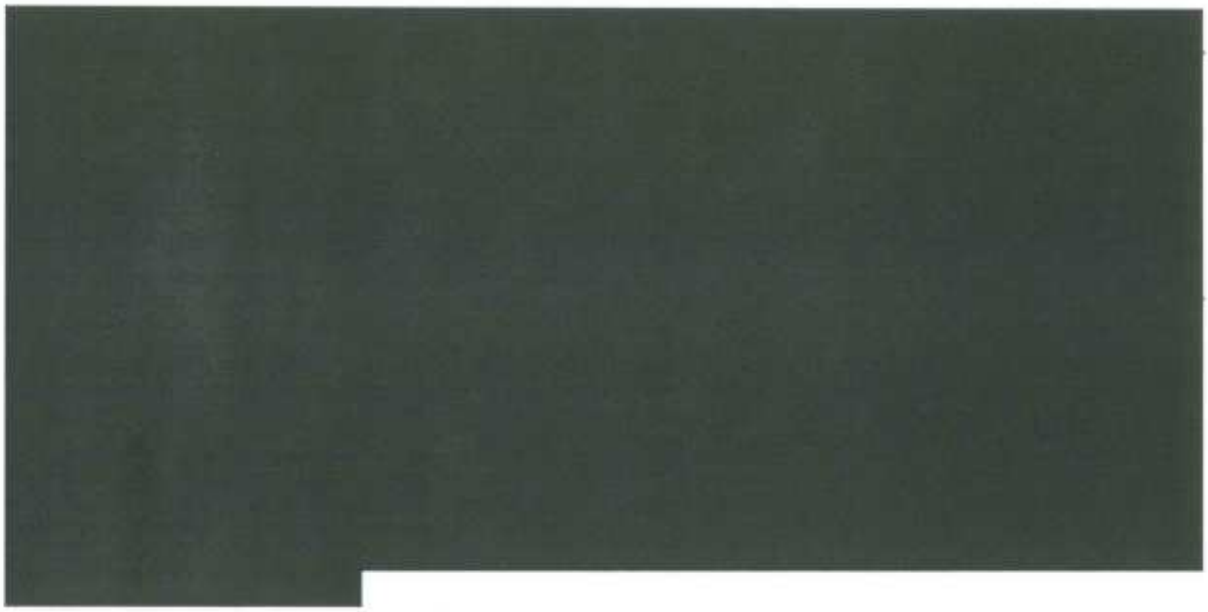
Escrow Agent to deliver such amounts to the Purchaser Indemnified Party and the remaining balance of the Indemnity Escrow Fund will be retained in accordance with the terms of this Section 8.08 and the Escrow Agreement.

(b) In the event that Purchaser will have made claim(s) for Losses pursuant to Section 8.02(a)(i) and such indemnification claim(s) remain outstanding as of the date of the expiration of the Indemnity Escrow Period, then the Indemnity Escrow Fund will only be delivered to Seller to the extent that the amount of such indemnification claim(s) (the "Claim Amount"), is less than the remaining balance of the Indemnity Escrow Fund, in which case, (i) within two (2) Business Days after the expiration of the Indemnity Escrow Period, Purchaser and Seller will execute a joint written instruction to the Escrow Agent directing the Escrow Agent to deliver to Seller an amount equal to the remaining balance of the Indemnity Escrow Fund less the Claim Amount, (ii) Purchaser and Seller will execute any required amendments to the Escrow Agreement in order to extend the Indemnity Escrow Period and (iii) the portion of the Indemnity Escrow Fund equal to the Claim Amount will remain held in escrow pending the resolution of such indemnification claim. Upon resolution of such outstanding indemnification claim(s), either by mutual agreement of the parties or pursuant to a final Order, Purchaser and Seller will promptly execute a joint written instruction to the Escrow Agent directing the Escrow Agent to deliver to (A) Purchaser any amounts which Purchaser is entitled to receive as a result of the resolution of such outstanding indemnification claims(s) and (B) Seller any remaining balance of the Indemnity Escrow Fund.

(c) Interest on the Indemnity Escrow Amount will be paid to Purchaser and Seller in the proportion of the Indemnity Escrow Amount paid to them.

(d) Purchaser will make demand for payment under the Escrow Agreement prior to instituting any proceedings or taking any other action against Seller, unless the failure to institute proceedings or take such other action will prejudice Purchaser's ability to make such indemnification claim.

Section 8.09 Indemnification Letter of Credit. At the Closing, Seller may deliver to Purchaser a letter of credit in the amount of [redacted] and substantially in the form of Exhibit E attached hereto (the "Indemnification Letter of Credit") to secure Seller's indemnification obligations under Section 8.02(a)(i), subject to the terms and conditions of this Agreement, in which event the Base Purchase Price will not be reduced by the Indemnity Escrow Amount and Purchaser and Seller will not enter into the Escrow Agreement at Closing, as to the Indemnity Escrow Fund. The Indemnification Letter of Credit must be issued by a U.S. commercial bank or the U.S. branch of a foreign bank with total assets of at least $10 billion having a general long-term senior unsecured debt rating of A- or higher (as rated by Standard & Poor's Rating Group) or A3 or higher (as rated by Moody's Investor Services, Inc.) and shall permit presentation at a bank located in Charlotte, NC, Atlanta, GA, or New York, NY (the "Indemnification LOC Issuing Bank"). Seller would ensure that the Indemnification Letter of Credit remains in full force, outstanding and in the required amount until the later of (i) the date which is [redacted]



ARTICLE IX

TERMINATION

Section 9.01 Termination. This Agreement may be terminated, and the transactions contemplated hereby may be abandoned, at any time by written notice from either party to the other party (except for paragraph (a) below):

(a) by mutual written consent of Purchaser and Seller;

(b) by either Purchaser or Seller:

(i) if the Closing has not occurred on or before March 31, 2017 (the "Termination Date"); provided, that the terminating party is not in material breach under this Agreement, and subject to Seller's right to extend the Termination Date for up to ninety (90) days pursuant to Section 5.06(b)(ii);

(ii) at any time before the Closing, if any court of competent jurisdiction in the United States or other Governmental or Regulatory Authority other than FERC shall have issued a final Order or enacted any Law or taken any other final action restraining, enjoining or otherwise prohibiting the consummation of the transactions contemplated by this Agreement and such Order or Law or other action is or shall have become final and nonappealable; provided, however, that the party seeking to terminate this Agreement pursuant to this Section 9.01(b)(ii) shall have used commercially reasonable efforts to prevent the entry of and to remove such Order or final action;

(iii) if [redacted] occur prior to August 1, 2015 and the terminating party reasonably determines that the cost of repairing, replacing or restoring the damaged assets will exceed [redacted] of the Base Purchase Price, provided that the terminating party provides notice on or prior to August 1, 2015;

(iv) [redacted]

(v) [redacted]

(vi) [redacted]

(vii) at any time before the Closing [redacted], instituted or pending any suit, action or proceeding by the DOJ, the FTC or the Florida attorney general's office seeking to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated by this Agreement provided notice of termination is given within 30 days of such threat in writing or the commencement of such proceeding, as applicable; or

(viii) if [redacted] and/or Other Losses occur [redacted]

(c) by:

(i) [redacted]

(ii) [redacted]

(iii) Purchaser or Seller, at any time before the Closing, if the FPSC affirmatively rejects the transactions contemplated hereby, provided notice of termination is given within 30 days after such FPSC rejection;

(iv) [redacted]

[redacted]; or

(v) [redacted]

(d) at any time before the Closing, by Purchaser (provided that Purchaser is not in material breach under this Agreement) if (A) there has been a breach by Seller of any representation, warranty, covenant or agreement contained in this Agreement or if any representation or warranty of Seller shall have become untrue, in either case such that the conditions set forth in Section 6.01 or 6.02 would not be satisfied, and (B) such breach is not curable by the Termination Date;

(e) at any time before the Closing, by Seller (provided that Seller is not in material breach under this Agreement) if (A) there has been a breach by Purchaser of any representation, warranty, covenant or agreement contained in this Agreement or if any representation or warranty of Purchaser shall have become untrue, in either case such that the conditions set forth in Section 7.01 or 7.02 would not be satisfied, and (B) such breach is not curable by the Termination Date; provided, however, that no cure period shall apply to Purchaser's obligation to pay the Closing Payment.

Section 9.02 Effect of Termination. Subject to Section 9.03, if this Agreement is validly terminated pursuant to Section 9.01, this Agreement will forthwith become null and void and there will be no liability or obligation on the part of either Purchaser or Seller (or any of their respective Affiliates or Representatives) in respect of this Agreement; provided, that the provisions set forth in Article X and Purchaser's indemnification obligations set forth in Section 5.01(a), Section 5.02(b), Section 5.06(c), and Section 5.11(d), will continue to apply following any termination hereof; and provided, further, that subject to Section 9.03, each party shall continue to be liable for any breach by such party prior to the termination of this Agreement of any representation, warranty, covenant or agreement of such party in this Agreement.

Section 9.03 [redacted] (a) [redacted]

[redacted]

(b) [redacted]

Section 9.04 Specific Performance.

(a) Except as provided in the last sentence of Section 9.03, the parties to this Agreement agree that, upon a breach or threatened breach of their Agreement by any party, the remedies at law of the other party for a breach or threatened breach of this Agreement may not be a sufficient remedy and that the party shall be entitled to specific performance of the terms of

this Agreement and immediate injunctive relief, without the necessity of proving the inadequacy of money damages as a remedy, in addition to any other remedy at law or in equity.

(b) The parties further agree that (i) the seeking of the remedies provided for in Section 9.04(a) by another party to this Agreement shall not be required to provide any bond or other security in connection with such order or injunction or in any respect constitute a waiver by either party of its right to seek any other form of relief that may be available to either of them under this Agreement, from and after the Closing, and (ii) nothing set forth in this Agreement shall require any party hereto to institute any proceeding for (or limit such party's right to institute any proceeding for) specific performance under Section 9.04(a) prior to or as a condition to exercising any termination right under Article IX, nor shall the commencement of any legal proceeding pursuant to this Section 9.04 restrict or limit any party's right to terminate this Agreement in accordance with the terms of Article IX or pursue any other remedies under this Agreement that may be available then or thereafter.

ARTICLE X

MISCELLANEOUS

Section 10.01 Entire Agreement. This Agreement, together with the Ancillary Agreements and the Confidentiality Agreement, supersedes all prior discussions and agreements between the parties with respect to the subject matter hereof, and contains the sole and entire agreement between the parties hereto with respect to the subject matter hereof. For clarity, the term "Proprietary Information" in the Confidentiality Agreement shall be deemed to include this Agreement.

Section 10.02 Expenses.

(a) Except as otherwise specified in this Agreement, whether or not the transactions contemplated hereby are consummated, each party shall pay its own costs and expenses (including attorneys' fees) incurred in connection with the negotiation and execution of this Agreement and the transactions contemplated hereby.

(b) Purchaser shall pay 100% of any filing fees associated with a filing made in 2014 or 2015 under the HSR Act.

(c) Purchaser and Seller shall each pay 50% of: [redacted]

Section 10.03 Announcements. Except as otherwise required by Law (including rules of any national securities exchange), each of Purchaser and Seller will, and will cause their Affiliates (as applicable) to, consult with the other regarding the timing and content of any press releases or public statements with respect to this Agreement or the transactions contemplated hereby.

Section 10.04 No Waiver. Any term or condition of this Agreement may be waived at any time by the party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the party waiving such term or condition. No waiver by any party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion.

Section 10.05 Amendments. Any provision of this Agreement may be modified, supplemented or waived only by an instrument in writing duly executed by the parties. Any such modification, supplement or waiver shall be for such period and subject to such conditions as shall be specified in the instrument effecting the same and shall be binding upon each of the parties, and any such waiver shall be effective only in the specific instance and for the purposes for which given.

Section 10.06 Addresses for Notices. All notices and other communications required or permitted to be given or made under this Agreement shall be given or made in writing, by physical (including by mail or courier) or facsimile or electronic mail delivery to the address specified below or such other address as shall be designated in a notice in writing. Notices will be effective upon receipt.

If to Seller:

Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, TX 77002
Attention: Chief Legal Officer
Facsimile No.: (713) 830-8751 and (832) 325-1508

with a copy to:

White & Case LLP
1155 Avenue of the Americas
New York, NY 10036-2787
Attn: Michael S. Shenberg
Facsimile No.: (212) 354-8113
Email: mshenberg@whitecase.com

If to Purchaser:

Duke Energy Florida, Inc.
299 First Avenue North
St. Petersburg, FL 33701
Attn: John Burnett

Facsimile No.: (727) 820-5041
Email: john.burnett@duke-energy.com

with a copy to:

Duke Energy Corporation
550 S. Tryon Street, DEC
Charlotte, North Carolina 28202
Attn: Greer Mendelow, Esq.
Facsimile No.: (980) 373-8534
Email: greer.mendelow@duke-energy.com

and

Parker Poe Adams & Bernstein LLP
401 S. Tryon Street, Suite 3000
Charlotte, North Carolina 28202
Attention: Roy L. Smart, III
Facsimile No.: (704) 334-4706
Email: skipsmart@parkerpoe.com

Section 10.07 Captions. The captions and section headings appearing in this Agreement are included solely for convenience of reference and are not intended to affect the interpretation of any provision of this Agreement.

Section 10.08 Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions of this Agreement, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 10.09 Assignment. The obligations of the parties under this Agreement are not assignable without the prior written consent of the other party, which such party may withhold in its discretion; provided, that, either party may assign this Agreement to an Affiliate of such party; and provided, further that the Parent Guaranty shall remain in full force and effect and shall be amended to the reasonable satisfaction of Seller in connection with any assignment by Purchaser to an Affiliate.

Section 10.10 No Third-Party Beneficiary. The terms and provisions of this Agreement are intended solely for the benefit of each party hereto and their respective successors or permitted assigns, and it is not the intention of the parties to confer third-party beneficiary rights upon any other Person other than any Person entitled to indemnity under Article VIII.

Section 10.11 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties to this Agreement may execute this Agreement by signing any such counterpart.

Section 10.12 Governing Law. Except for matters relating to the Real Property, this Agreement shall be governed by, and construed in accordance with, the Laws of the State of New York applicable to a contract executed and performed in such State, which shall be without giving effect to any choice of law or conflict of law rules or principles thereof that would require the application of the rules of another jurisdiction. Matters relating to the Real Property shall be governed by, and construed in accordance with, the Laws of the State of Florida applicable to a contract executed and performed in such State, which shall be without giving effect to any choice of law or conflict of law rules or principles thereof that would require the application of the rules of another jurisdiction.

Section 10.13 Consent to Jurisdiction.

(a) Except as provided in Section 5.06(b)(iii), for all purposes of this Agreement, and for all purposes of any Action or Proceeding arising out of or relating to the transactions contemplated hereby or for recognition or enforcement of any judgment, each party hereto submits to the exclusive jurisdiction of the courts of the State of New York and the federal courts of the United States sitting in New York County, the Borough of Manhattan, and hereby irrevocably and unconditionally agrees that any such Action or Proceeding shall be heard and determined in such New York court or, to the extent permitted by law, in such federal court. Each party hereto agrees that a final judgment in any such Action or Proceeding may be enforced in any other jurisdiction by suit on the judgment or in any other manner provided by law.

(b) Each party hereto irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so:

(i) any objection which it may now or hereafter have to the laying of venue of any Action or Proceeding arising out of or relating to this Agreement or any related matter in any New York state or federal court located in New York County, the Borough of Manhattan; and

(ii) the defense of an inconvenient forum to the maintenance of such Action or Proceeding in any such court.

(c) Each party hereto irrevocably consents to service of process by registered mail, return receipt requested, as provided in Section 10.06. Nothing in this Agreement will affect the right of any party hereto to serve process in any other manner permitted by law.

Section 10.14 WAIVER OF JURY TRIAL. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH PARTY HEREBY WAIVES ALL RIGHTS TO A TRIAL BY JURY IN ANY LEGAL ACTION TO ENFORCE OR INTERPRET THE PROVISIONS OF THIS AGREEMENT OR THAT OTHERWISE RELATES TO THIS AGREEMENT.

Section 10.15 Disclosure. Seller may, at its option, include in the Seller Disclosure Schedule items that are not material in order to avoid any misunderstanding, and any such inclusion, or any references to dollar amounts, shall not be deemed to be an acknowledgment or representation that such items are material, to establish any standard of materiality, to define further the meaning of such terms for purposes of this Agreement or to be deemed an admission by Seller that such item represents a material exception or fact, event, or circumstance or that

such item would reasonably be expected to have a Material Adverse Effect. Information disclosed in any section of the Seller Disclosure Schedule, including the agreements and documents referred to in the Seller Disclosure Schedule, shall constitute a disclosure for purposes of all other sections of the Seller Disclosure Schedule to the extent reasonably apparent, notwithstanding the lack of specific cross-reference thereto. In no event shall the inclusion of any matter in the Seller Disclosure Schedule be deemed or interpreted to broaden Seller's representations, warranties, covenants or agreements contained in this Agreement.

Section 10.16 DISCLAIMER. EXCEPT FOR AND SUBJECT TO THOSE REPRESENTATIONS AND WARRANTIES EXPRESSLY SET FORTH IN ARTICLE III THAT BY THE TERMS OF THIS AGREEMENT EXPRESSLY SURVIVE AFTER THE CLOSING DATE AND ANY REPRESENTATIONS AND WARRANTIES IN THE ANCILLARY AGREEMENTS, (I) NONE OF SELLER OR ANY OF ITS AFFILIATES OR REPRESENTATIVES HAS MADE OR IS MAKING ANY REPRESENTATION OR WARRANTY WHATSOEVER, EXPRESS OR IMPLIED, WRITTEN OR ORAL, INCLUDING ANY IMPLIED REPRESENTATION OR WARRANTY AS TO THE CONDITION, VALUE, QUALITY, MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, APPARENT OR LATENT DEFECTS OF ANY TYPE, PROSPECTS (FINANCIAL OR OTHERWISE) OR RISKS OR OTHER INCIDENTS OF THE BUSINESS, THE PROJECT, THE PROJECT SITE, THE PURCHASED ASSETS, ASSUMED LIABILITIES OR ANY PART THEREOF, AND (II) THE SALE OF THE PURCHASED ASSETS IS BEING MADE "AS IS, WHERE IS, WITH ALL FAULTS". NONE OF SELLER OR ANY OF ITS AFFILIATES OR REPRESENTATIVES MAKES ANY REPRESENTATION OR WARRANTY REGARDING ANY FINANCIAL OR OTHER PROJECTIONS, FORECASTS, ESTIMATES, OR FORWARD LOOKING STATEMENTS OF ANY KIND OR NATURE WHATSOEVER RELATING TO THE BUSINESS, THE PROJECT, THE PROJECT SITE, THE PURCHASED ASSETS OR THE ASSUMED LIABILITIES. NOTHING IN THE FOREGOING SHALL LIMIT ANY CLAIM, ACTION OR PROCEEDING WITH RESPECT TO FRAUD OR INTENTIONAL MISREPRESENTATION.

Section 10.17 Florida Law Disclosure. The following disclosure is made pursuant to Florida Law:

"RADON GAS: Radon is a naturally occurring radioactive gas that, when it has accumulated in a building in sufficient quantities, may present health risks to persons who are exposed to it over time. Levels of radon that exceed federal and state guidelines have been found in buildings in Florida. Additional information regarding radon and radon testing may be obtained from your county health department."

Section 10.18 Time is of the Essence. The parties agree that time shall be of the essence in the performance of all of the terms and conditions of this Agreement. If the last day for the exercise of any privilege or the discharge of any duty under this Agreement shall fall upon a day which is not a Business Day hereunder, then the party having such privilege or duty shall have until 5:00 p.m. local time on the next succeeding regular Business Day to exercise such privilege or to discharge such duty.

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each party hereto as of the date first above written.

DUKE ENERGY FLORIDA, INC.

By _____
Name: Alex Glenn
Title: State President - FL

DUKE ENERGY, INC.
LEGAL DEPARTMENT
APPROVED BY: _____
DATE: 12/16/14

OSPREY ENERGY CENTER, LLC

By _____
Name:
Title:

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each party hereto as of the date first above written.

DUKE ENERGY FLORIDA, INC.

By _____
Name: Alex Glenn
Title: State President - FL

OSPREY ENERGY CENTER, LLC

By _____ TJD
Name: Thad Hill
Title: President

[EXECUTION COPY]

Seller Disclosure Schedule

This Seller Disclosure Schedule (this "Seller Disclosure Schedule") has been prepared and delivered in accordance with the Asset Purchase and Sale Agreement, dated as of December 17, 2014 (the "Agreement"), by and between Duke Energy Florida, Inc., a Florida corporation ("Purchaser"), and Osprey Energy Center, LLC, a Delaware limited liability company ("Seller" or "Company"). Unless the context otherwise requires, capitalized terms used but not defined in this Seller Disclosure Schedule shall have the respective meanings assigned to such terms in the Agreement.

Seller may, at its option, include in the Seller Disclosure Schedule items that are not material, and any such inclusion, or any references to dollar amounts, shall not be deemed to be an acknowledgement or representation that such items are material, to establish any standard of materiality, to define further the meaning of such terms for purposes of the Agreement or to be deemed an admission by Seller that such item represents a material exception or fact, event or circumstance or that such item would reasonably be expected to have a Material Adverse Effect. Nothing in any section of this Seller Disclosure Schedule (i) shall be deemed to modify in any respect the standard of materiality or any other standard for disclosure set forth in the Agreement or (ii) relating to any possible breach or violation of any agreement, contract, applicable Law or any order of a Governmental Authority shall be construed as an admission or indication that any such breach or violation exists or has actually occurred. In no event shall the inclusion of any matter in the Seller Disclosure Schedule be deemed or interpreted to broaden Seller's representations, warranties, covenants or agreements contained in this Agreement.

The section headings and subheadings in this Seller Disclosure Schedule are for convenience of reference only and shall not be deemed to alter or affect the express descriptions of this Seller Disclosure Schedule and its sections as set forth in the Agreement.

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1. [redacted], Vice President Corporate Development
2. [redacted] Senior Vice President Power Operations
3. [redacted] Vice President Development and Engineering
4. [redacted] Director Environmental Services
5. [redacted] Vice President Power Operations
6. [redacted] Plant Manager
7. [redacted] Vice President of Human Resources

Section 1.01(c)
Facility Employees

Calpine Operating Services Company	[redacted]	[redacted]	Osprey Energy Ctr	9054	Business Manager
Calpine Operating Services Company			Osprey Energy Ctr	9076	Chemical Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9073	IC&E Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9073	IC&E Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9073	IC&E Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9082	Maint Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9082	Maint Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9082	Maint Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9109	Materials Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9027	Mgr Maintenance
Calpine Operating Services Company			Osprey Energy Ctr	9026	Mgr Operations
Calpine Operating Services Company			Osprey Energy Ctr	9087	Operator Technician II
Calpine Operating Services Company			Osprey Energy Ctr	9087	Operator Technician II
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9075	Operator Technician III
Calpine Operating Services Company			Osprey Energy Ctr	9042	Plant Engineer III
Calpine Operating Services Company			Osprey Energy Ctr	9014	Plant Manager

As disclosed in Section 5.03(i) of the Seller Disclosure. [redacted]

Section 1.01(d)-1
Permitted Liens with respect to Real Property

1. All matters disclosed in the Title Commitment and the Survey.

2. Seller has had 100% of its limited liability company interests pledged as collateral in connection with the Credit Agreement, dated as of May 3, 2013 (as amended by Amendment No. 1, dated as of February 20, 2014, and as may be further amended, restated, amended and restated, supplemented or otherwise modified up through the date hereof), among Calpine Construction Finance Company, L.P., a Delaware limited partnership, as borrower, each of the lenders from time to time party thereto and Goldman Sachs Lending Partners LLC, as administrative agent and as collateral agent, pursuant to the Pledge and Security Agreement, dated as of June 3, 2013, among Calpine Construction Finance Company, L.P., as borrower, each of the grantors from time to time party thereto and Goldman Sachs Lending Partners LLC, as collateral agent. Such Liens (if any, on the Purchased Assets) will be discharged at Closing with respect to the Purchased Assets.

3. Seller may be required to grant a Mortgage, Assignment of Rents, Security Agreement and Fixture Filing to Goldman Sachs Lending Partners LLC (the "Goldman Mortgage"), as collateral agent, pursuant to the Credit Agreement described in paragraph 2 above. The Liens under the Goldman Mortgage, if granted, will be discharged at Closing.

Section 1.01(d)-2
Permitted Liens with respect to Purchased Assets (other than Real Property)

1. Seller has had 100% of its limited liability company interests pledged as collateral in connection with the Credit Agreement, dated as of May 3, 2013 (as amended by Amendment No. 1, dated as of February 20, 2014, and as may be further amended, restated, amended and restated, supplemented or otherwise modified up through the date hereof), among, Calpine Construction Finance Company, L.P., a Delaware limited partnership, as borrower, each of the lenders from time to time party thereto and Goldman Sachs Lending Partners LLC, as administrative agent and as collateral agent, pursuant to the Pledge and Security Agreement, dated as of June 3, 2013, among, Calpine Construction Finance Company, L.P., as borrower, each of the grantors from time to time party thereto and Goldman Sachs Credit Partners LLC, as collateral agent. Such Liens (if any, on the Purchased Assets) will be discharged at Closing with respect to the Purchased Assets.

2. Seller may be required to grant the Goldman Mortgage, pursuant to the Credit Agreement described in paragraph 2 above. The Liens under the Goldman Mortgage, if granted, will be discharged at Closing.

Section 2.01(j)
Warranties, Indemnities and Guarantees

None.

Section 2.02(d)
Excluded Contracts

1. [redacted]

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted]

6. [redacted]

[redacted]

7. [redacted]

8. [redacted]

9. [redacted]

10. [redacted]

11. [redacted]

12. [redacted]

13. [redacted]

14. [redacted]

15. [redacted]

16. [redacted]

Section 2.02(i)
Excluded Governmental and Regulatory Approvals

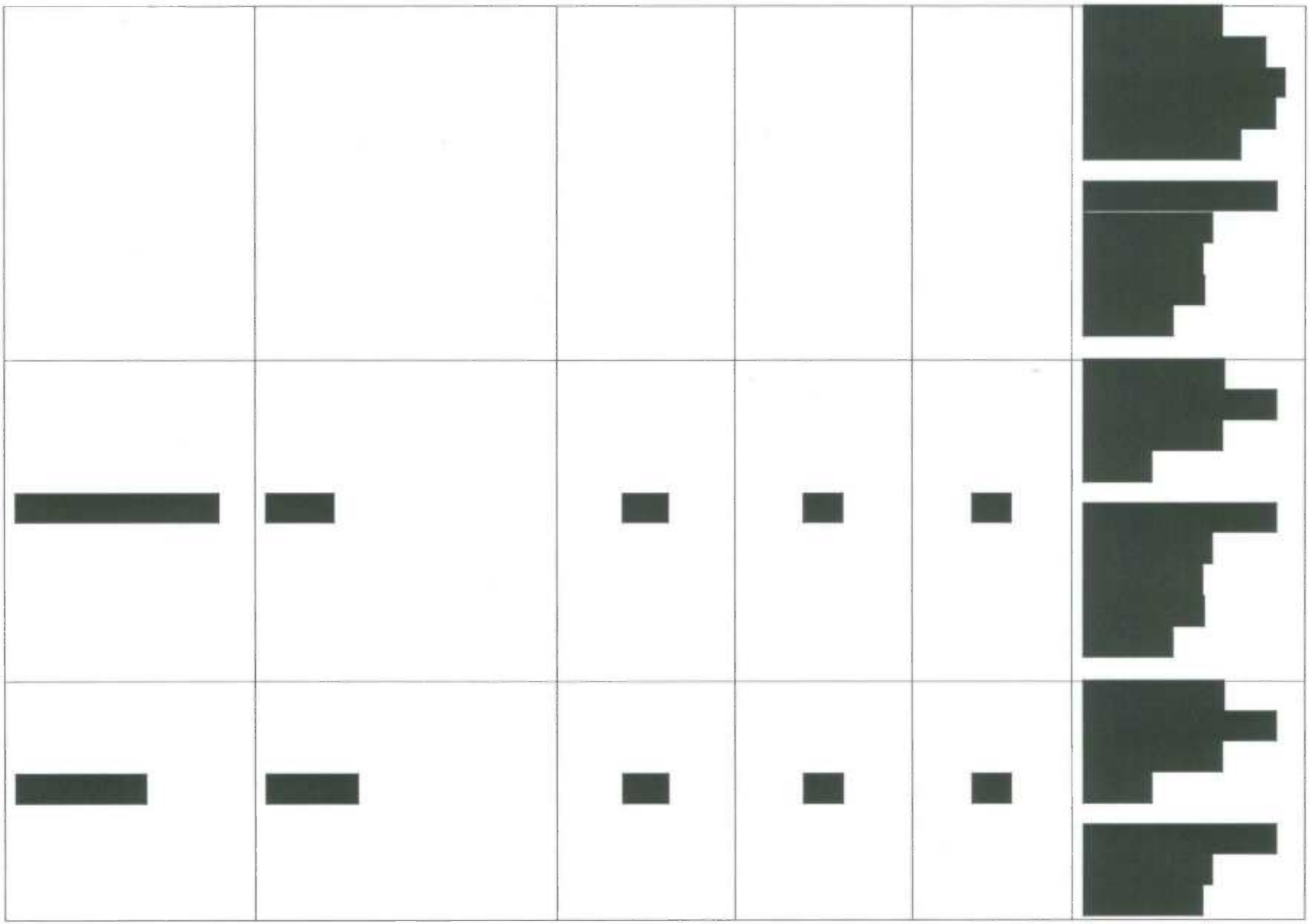
1. The MSGP identified in Section 3.17(b) of this Seller Disclosure Schedule is issued to Calpine Operating Services Company, Inc., an affiliate of the Company. Since an MSGP is not transferable to a new owner, Purchaser will be required to obtain an MSGP in its own name.

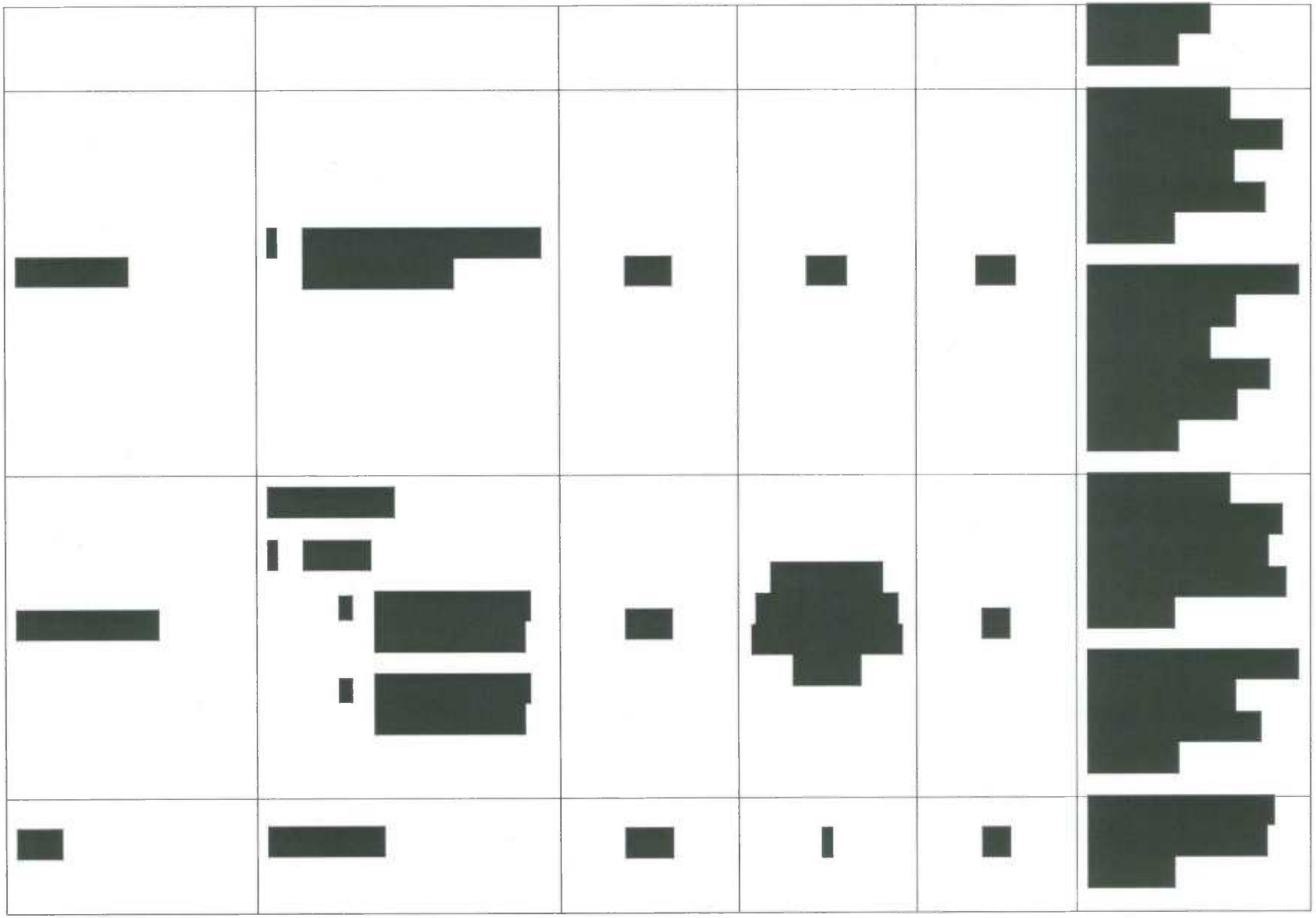
2. Notice of Self-Certification of Exempt Wholesale Generator Status, Docket No. EG13-39-000, filed June 10, 2013, as supplemented on July 26, 2013. FERC Notice of Effectiveness of Exempt Wholesale Generator Status, issued September 23, 2013.

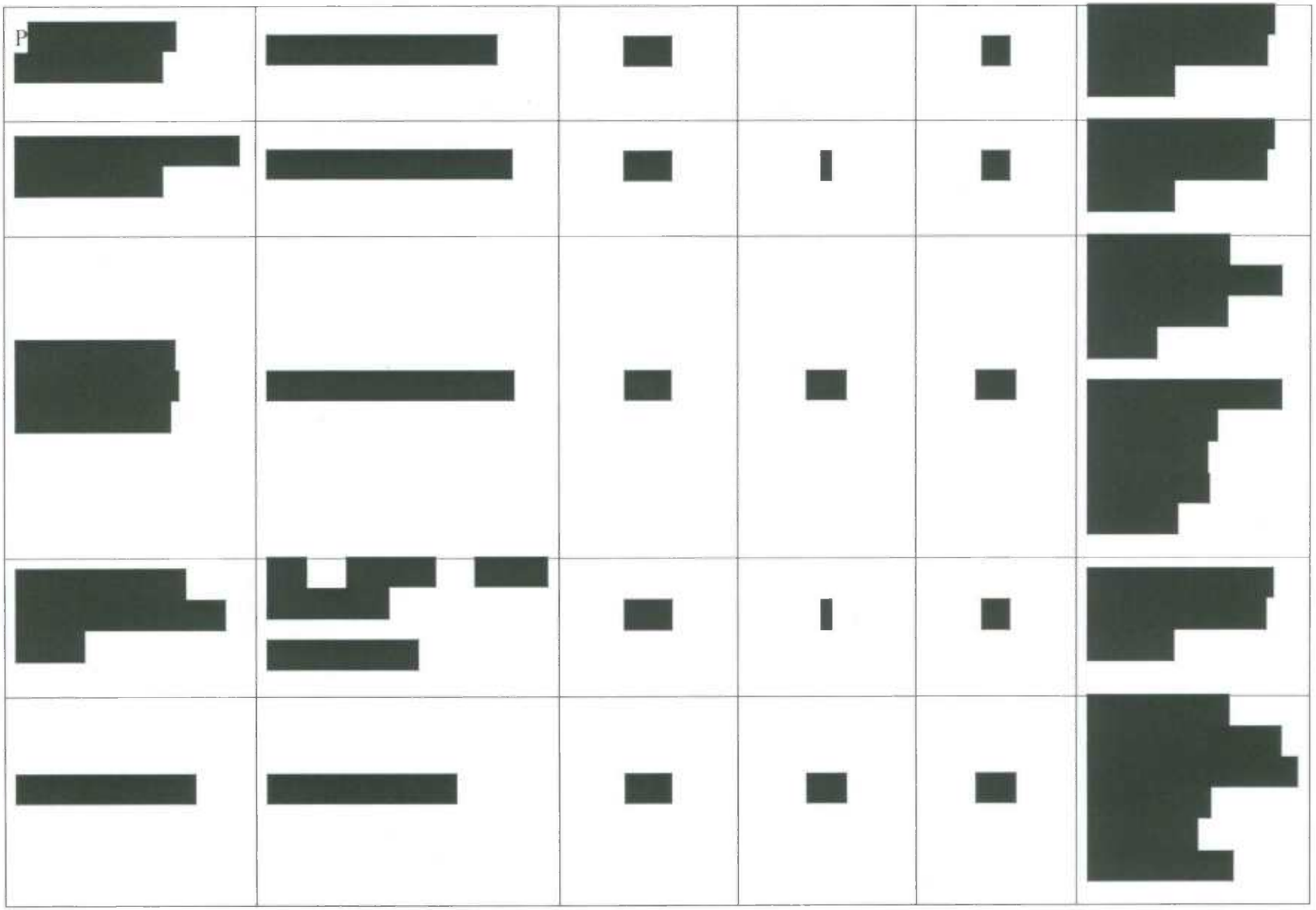
3. Market Based Rate Authorization: Osprey Energy Center, LLC, Docket No. ER13-1406-000, filed May 2, 2013, approved by FERC by letter order dated June 19, 2013.

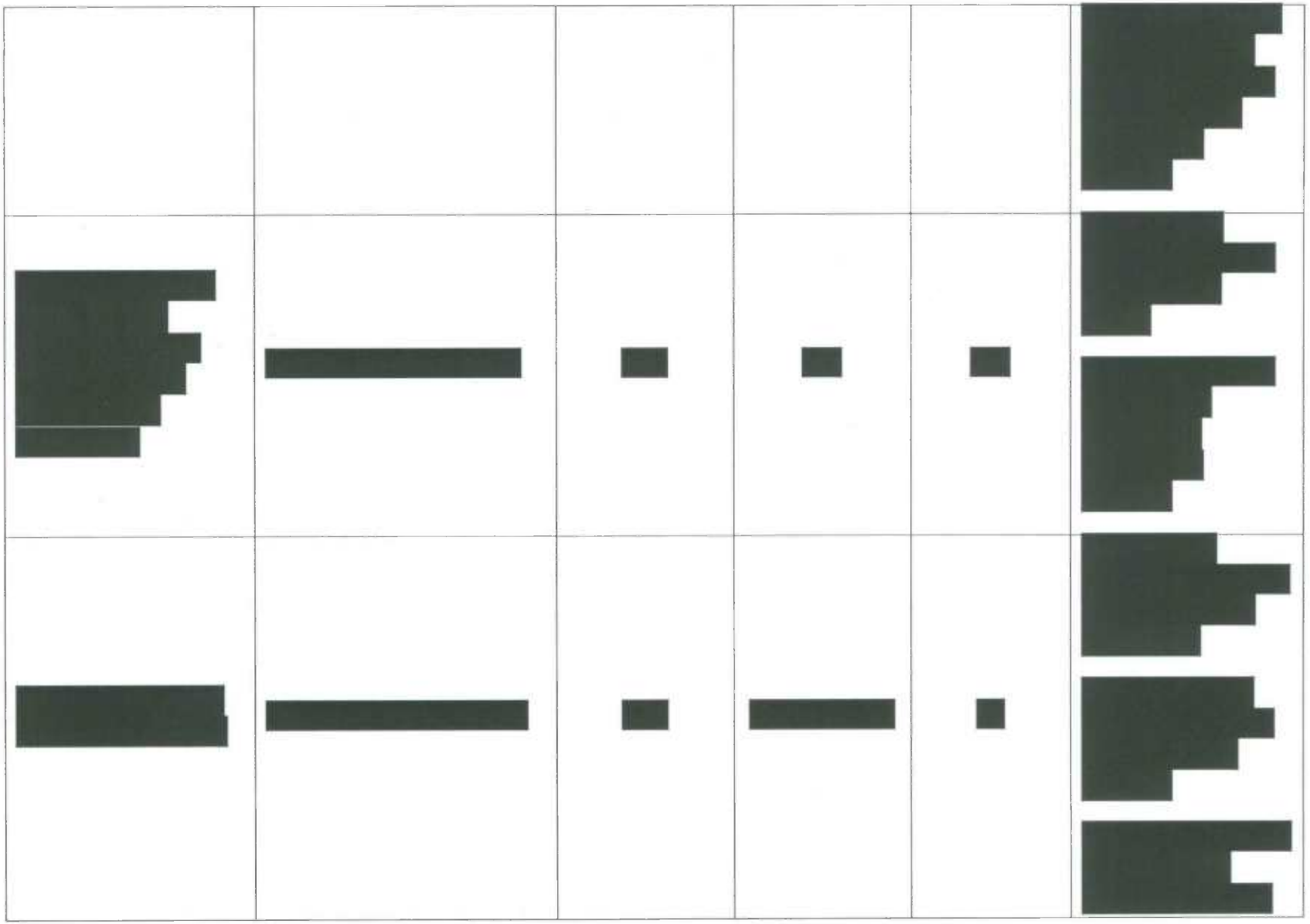
Section 2.02(j)
Excluded Intellectual Property; Excluded Tangible Personal Property; Excluded Software

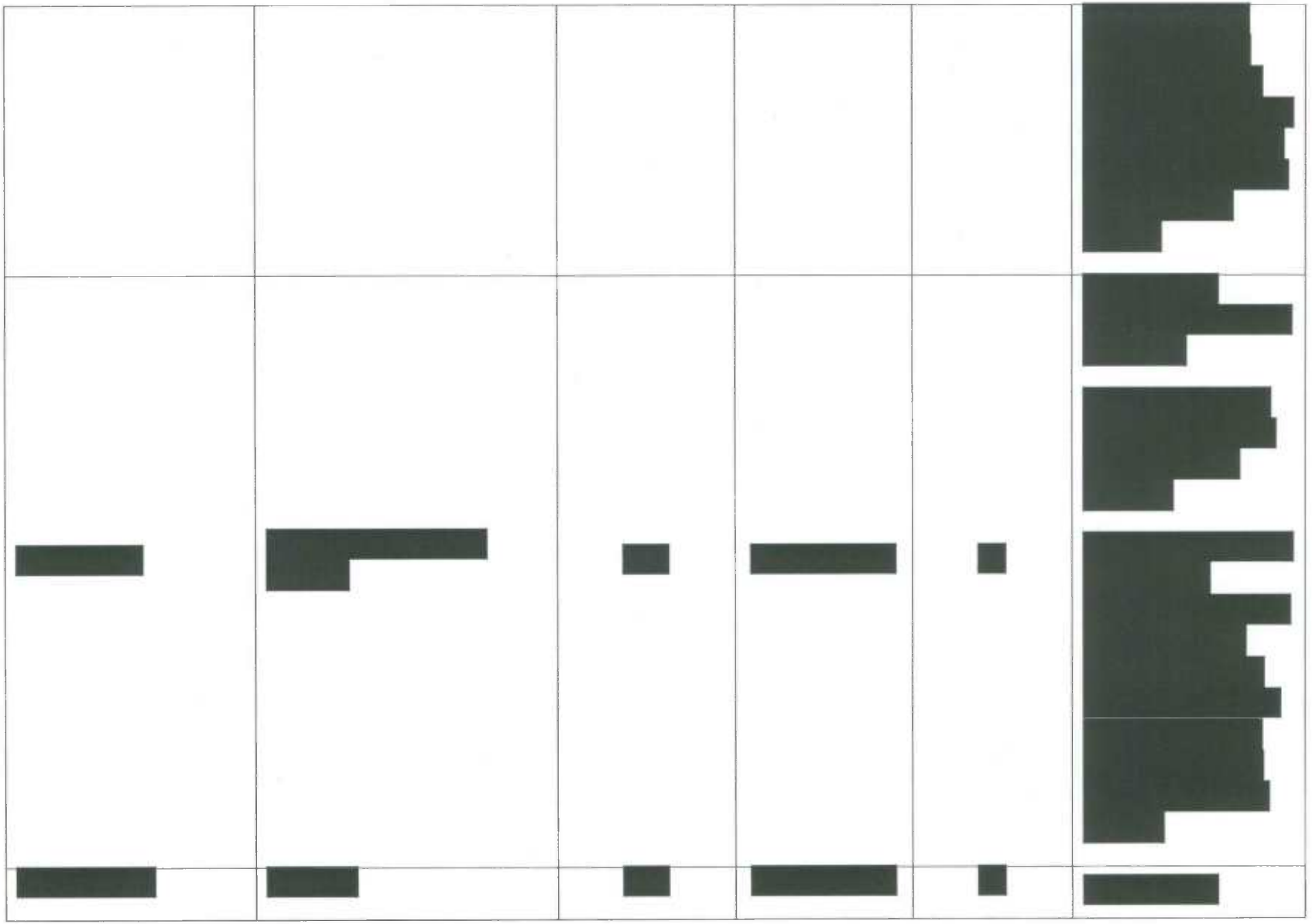
System Description	Product/License Detail	Licensed by Corp or Plant?	Number of Licenses by Type	Costs associated with transfer?	Excluded Intellectual Property; Excluded Tangible Personal Property; Excluded Software
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

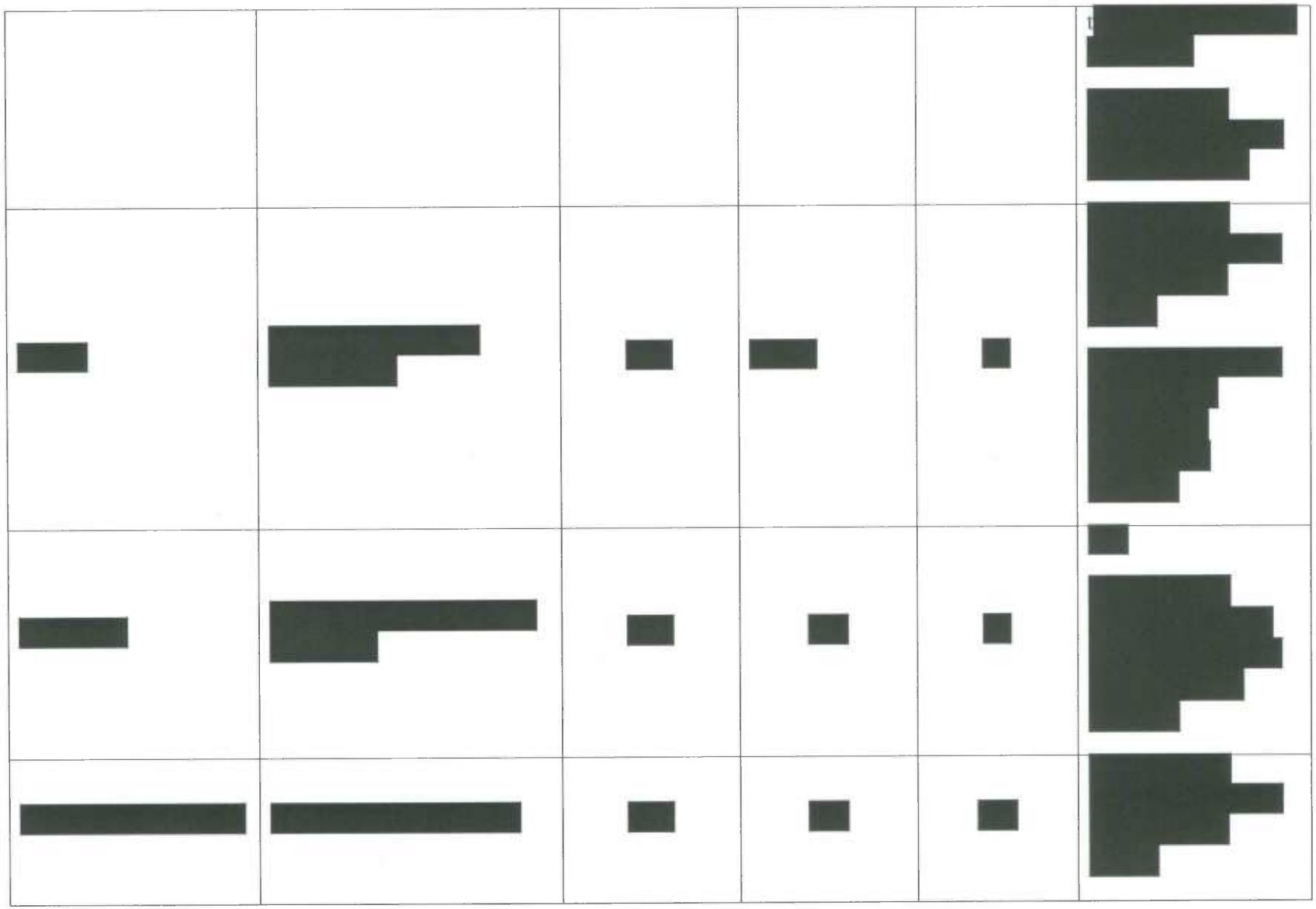


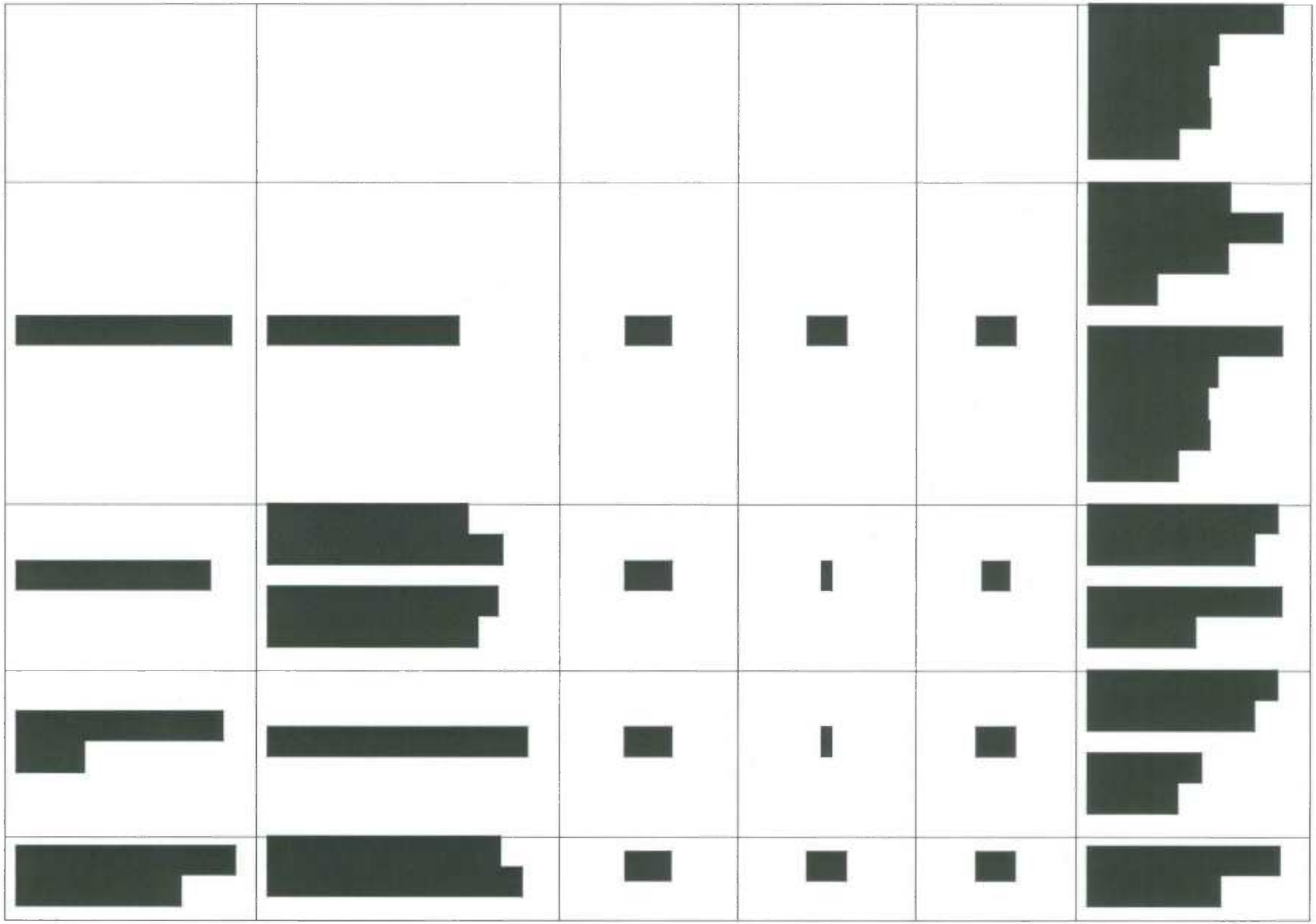


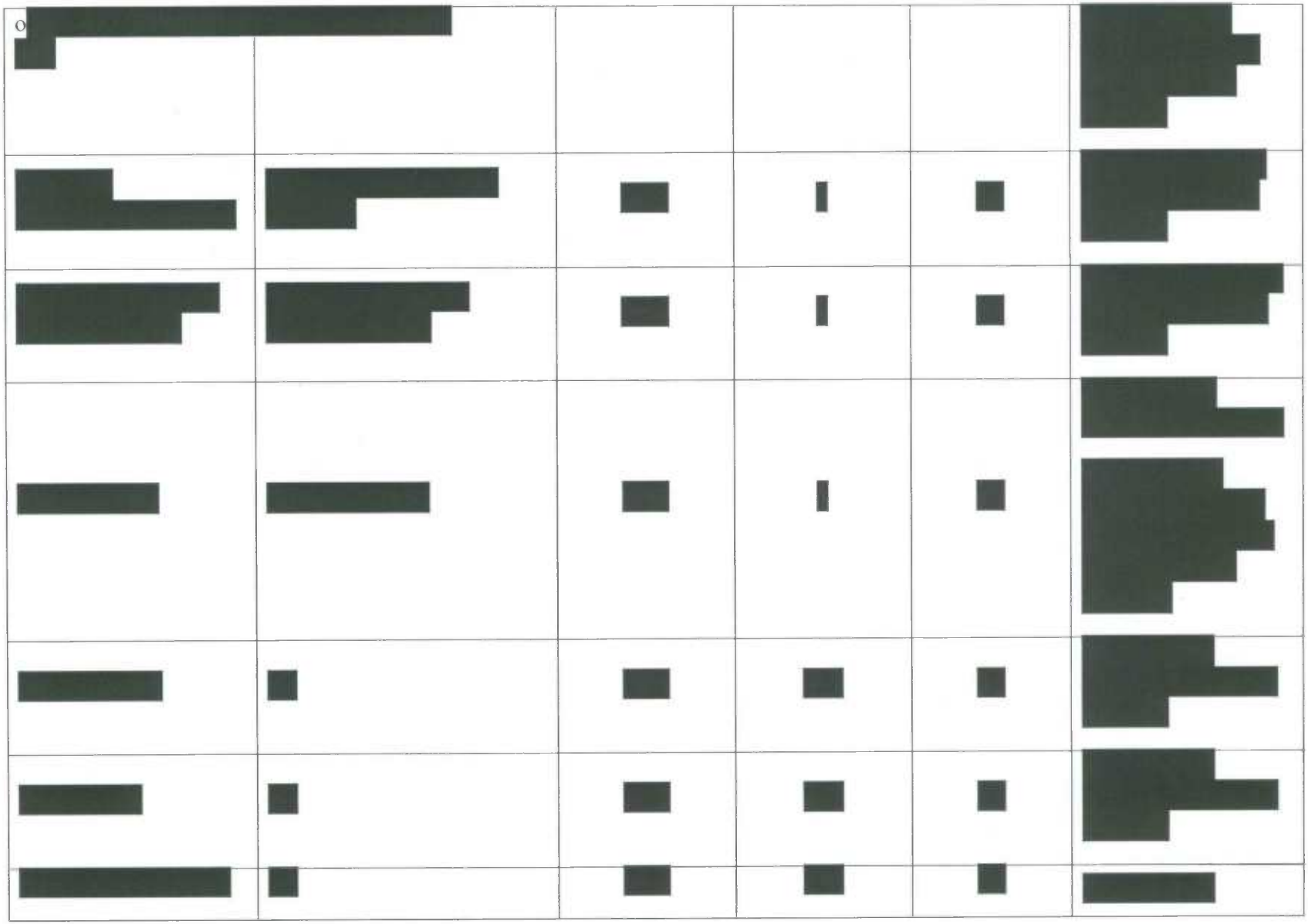


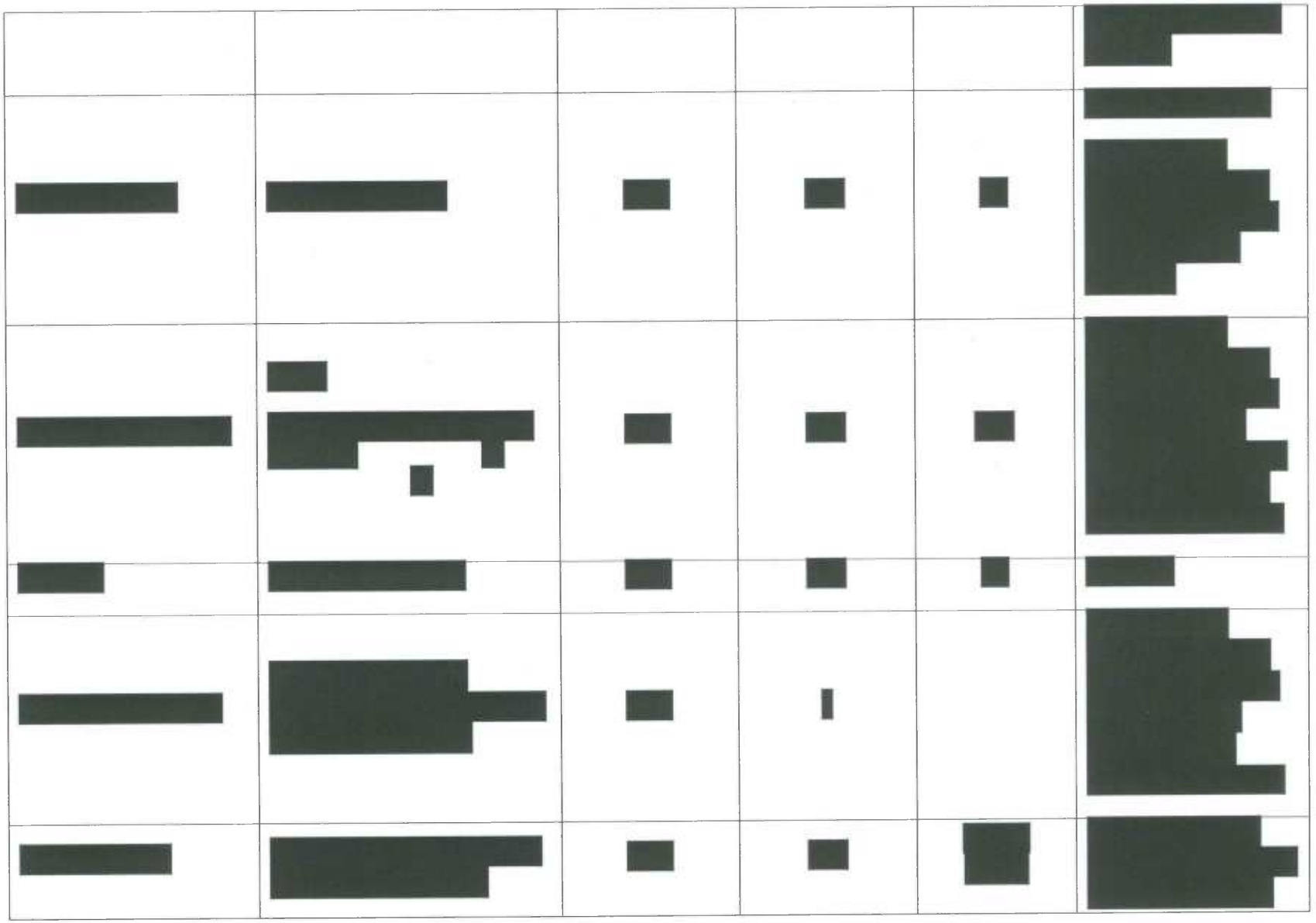


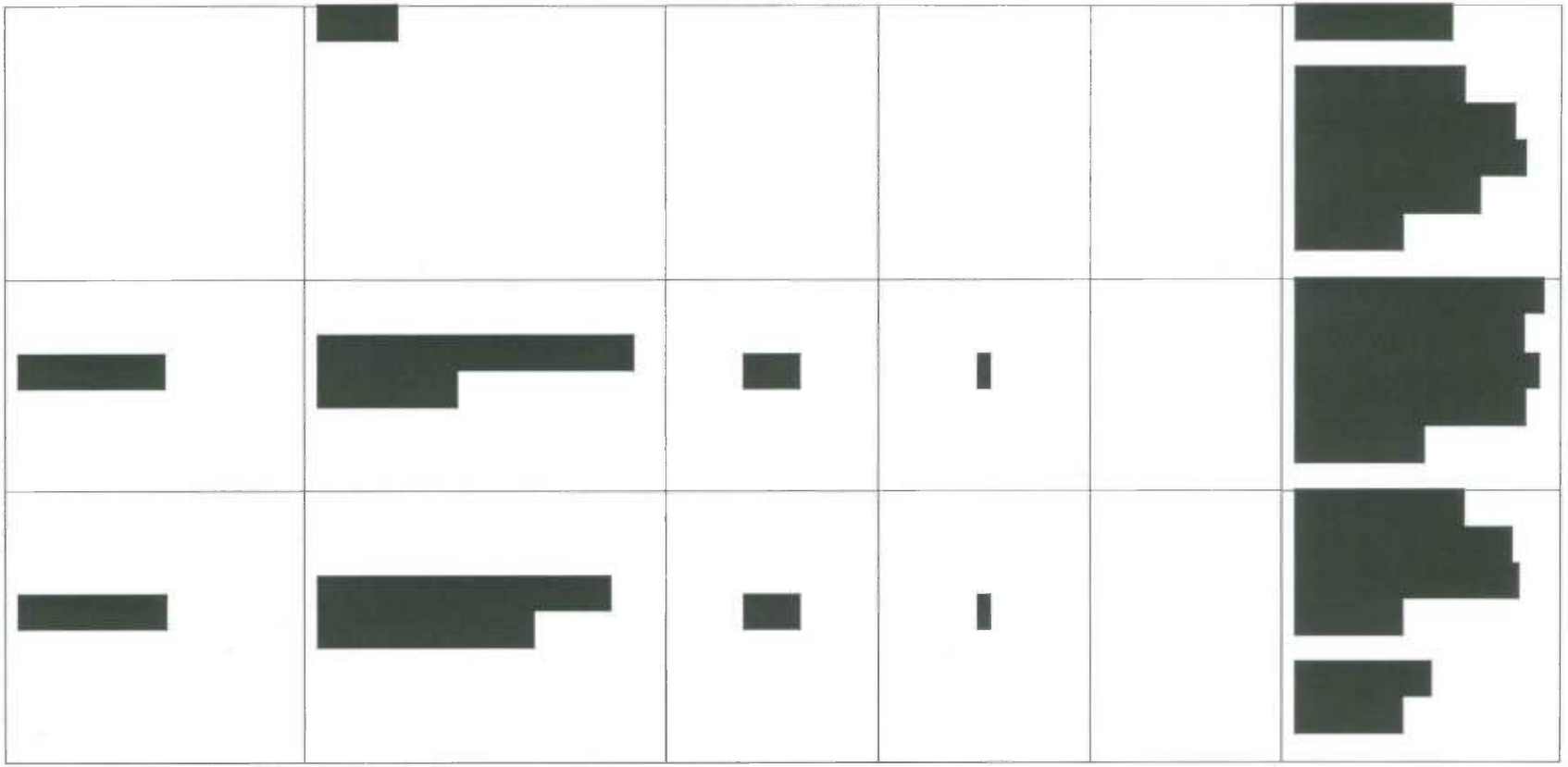












For the avoidance of doubt, Seller's Marks, as such term is defined in Section 5.14 of the Agreement are Excluded Intellectual Property.

Section 3.03(c)
No Conflict, Violation or Breach

1. Section 3.04 of this Seller Disclosure Schedule is incorporated herein by reference.

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted]

6. [redacted]

Section 3.04
Required Governmental or Regulatory Approvals

1. Section 7.05 of this Seller Disclosure Schedule is incorporated herein by reference.

2. The MSGP identified in Section 3.17(b) of this Seller Disclosure Schedule is issued to Calpine Operating Services Company, Inc., an affiliate of the Company. Since an MSGP is not transferable to a new owner, Purchaser will be required to obtain an MSGP in its own name. Post-closing notification and approval for coverage under the MSGP for Stormwater Associated with Industrial Activity.

3. Transfer of the certification under the Florida Power Plant Siting Act (PA0041) by filing of Notice of Intent to Transfer Certification with the Florida Department of Environmental Protection for certification and approval of the transfer.

4. Per the Power Plant Siting Act Conditions of Certification condition V.B.2, provide notification to SWFWMD within 30 days of closing of the transfer of the facility.

5. Approval of the City of Auburndale Public Utilities Department for the Wastewater Discharge Permit (*Permit No. IC8916).*

6. Modification, post-closing notification and permit transfer required for PSD/Title V Air Operation Permit, incorporating Clean Air Interstate Rule/Cross State Air Pollution Rule and Acid Rain permits, (*Permit Nos. 1050334, PSD-FL-287, and ORIS 55412)* issued by the FDEP.

7. Post-closing notification and assignment of a new EPA Identification Number required for Hazardous Waste Generator Identification Number (*ID: FLR000105544)* issued by the U.S. Environmental Protection Agency and FDEP.

8. Post-closing notification and transfer required for Storage Tank Registration (*Facility ID: 9806373 and STCM Account: 55776*) issued by the FDEP.

9. Post-closing notification for Greenhouse Gas Reporting Registration (ID: 1000107) issued by U.S. Environmental Protection Agency.

10. Post-closing notification for Emergency Planning and Community Right-to-Know Act for Tier II reporting to Florida Department of Emergency Management and Central Florida Regional Planning Council; Purchaser to obtain new ID for Tier II reporting.

Section 3.06
Undisclosed Liabilities

None.

Section 3.07
Absence of Changes

[redacted]

Section 3.08
Compliance with Laws

None.

Section 3.09
Legal Proceedings

None.

Section 3.10(a)
Real Property

The West ½ of the Northwest ¼ of the Northwest ¼ of Section 15, Township 28 South, Range 25 East, Polk County, Florida, less and except that certain property conveyed by Quit Claim deed recorded in deed book 972 page 357 and less and except that certain property conveyed by Quit Claim deed recorded in Official Records Book 666, page 640, and as modified by a Boundary Line Agreement recorded October 12, 2001 in Official Records Book 4822, Page 1799 and as amended by that certain First Amendment to Boundary Line Agreement recorded in Official Records Book 4837, Page 688 of the Public Records of Polk County, Florida.

Seller makes no representation or warranty with respect to any of the above-described land that is included within any road right of way.

Together with: (i) all structures and improvements constructed and/or located thereon and (ii) any and all rights, entitlements, privileges, easements, rights of way and/other appurtenances used or connected with the beneficial use or enjoyment of such land, if any.

Section 3.10(b)
Real Property Subject to Condemnation

None.

Section 3.11
Title to Personal Property

Certain of the Intellectual Property, Tangible Personal Property and Software as identified on Section 2.02(j) of this Seller Disclosure Schedule are Excluded Assets. Certain Tangible Personal Property as identified on Section 2.02(j) of this Seller Disclosure Schedule, used by the Company in the Business or for the Project is owned by an Affiliate of the Company.

Section 3.13
Company Contracts

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]
7. [redacted]
8. [redacted]
9. [redacted]

10. [redacted]

Section 3.14
Taxes

Section 3.15(a)
Benefit Plans

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]
7. [redacted]
8. [redacted]
9. [redacted]
10. [redacted]
11. [redacted]
12. [redacted]
13. [redacted]
14. [redacted]
15. [redacted]
16. [redacted]
17. [redacted]
18. [redacted]
19. [redacted]
20. [redacted]

[redacted]

21. [redacted]

22. [redacted]

23. [redacted]

24. [redacted]

25. [redacted]

26. [redacted]

Section 3.15(c)
Acceleration of Vesting or Payment

None.

Section 3.15(f)
Strikes, Lockouts or Other Labor Stoppages

None.

Section 3.16(a)
Project Insurance Policies

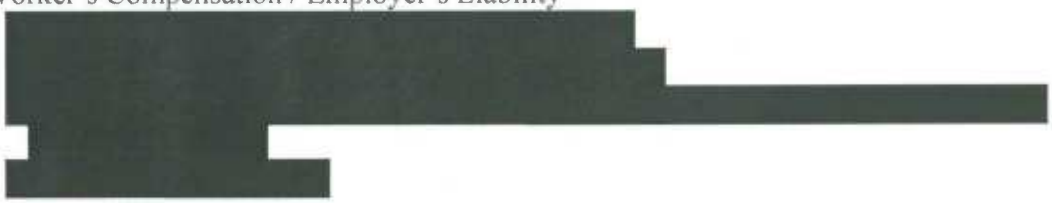
The policies listed below are part of a master corporate insurance program and all limits are shared among Calpine Corporation's fleet. For the avoidance of doubt, none of the policies set forth below will provide any coverage to Purchaser after Closing.

1. Property and Business Interruption Insurance

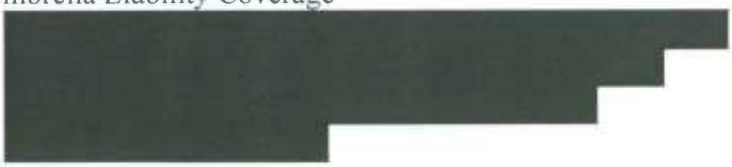
2. General Liability Insurance

3. Auto Liability Insurance

4. Worker's Compensation / Employer's Liability



5. Umbrella Liability Coverage



6. First Excess Liability

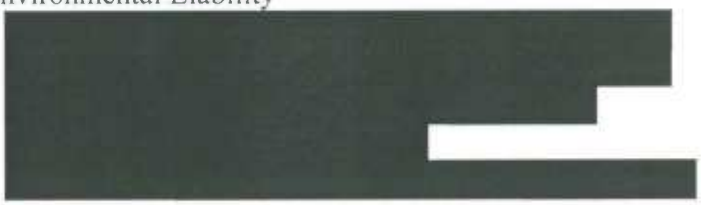
7. Second Excess Liability

8. Third Excess Liability

9. Fourth Excess Liability

10. Fifth Excess Liability

11. Environmental Liability



Section 3.16(b)
Insurance Claims

None.

Section 3.17(a)
Environmental Matters

1. All matters disclosed in the Phase I Environmental Site Assessment Update Report – Osprey Energy Center Site, Auburndale, Florida, prepared by Golder Associates, Inc. and ENVIRON International Corporation and dated May 20, 2003.

Section 3.17(b)
Environmental Permits

1. Conditions of Certification (*ID: PA-0041)* issued by the Florida Governor and Cabinet (issuance) and coordinated by the FDEP.

2. PSD/Title V Air Operation Permit incorporating Clean Air Interstate Rule/Cross State Air Pollution Rule and Acid Rain permits, (*Permit Nos. 1050334, PSD-FL-287, and ORIS 55412)* issued by the FDEP expiring December 31, 2015.

3. Multi Sector Generic Permit for Stormwater Associated with Industrial Activity (*Facility ID: FLR05G127)* issued to Calpine Operating Services Company, Inc. by the FDEP expiring January 6, 2016.

4. Wastewater Discharge Permit (*Permit No. IC8916)* issued by the City of Auburndale Public Utilities Department expiring July 31, 2015.

5. Hazardous Waste Generator Identification Number (*ID: FLR000105544)* issued by the U.S. Environmental Protection Agency and FDEP.

6. Storage Tank Registration (*Facility ID: 9806373 and STCM Account: 55776*) issued by the FDEP with no expiration.

7. Greenhouse Gas Reporting Registration (ID: 1000107) issued by U.S. Environmental Protection Agency.

8. Post-closing notification for Emergency Planning and Community Right-to-Know Act for Tier II reporting to Florida Department of Emergency Management and Central Florida Regional Planning Council; Purchaser to obtain new ID for Tier II reporting.

Section 3.18(a)
Permits and Regulatory Matters

1. The Permits listed under Section 3.17(b) of this Seller Disclosure Schedule.

2. Notice of Self-Certification of Exempt Wholesale Generator Status, Docket No. EG13-39-000, filed June 10, 2013, as supplemented on July 26, 2013. FERC Notice of Effectiveness of Exempt Wholesale Generator Status, issued September 23, 2013.

3. Market Based Rate Authorization: Osprey Energy Center, LLC, Docket No. ER13-1406-000, filed May 2, 2013, approved by FERC by letter order dated June 19, 2013.

Section 3.18(b)
Permits and Regulatory Approvals not in Full Force and Effect

None.

Section 3.20(a)
Good Utility Practice Exceptions

None.

Section 3.20(b)
Auburndale Plant Interdependencies; Separation Plan

[redacted]

Section 5.03
Certain Restrictions (Exceptions)

1. Items listed under Section 5.03(e) and Section 5.03(i) of this Seller Disclosure Schedule.

Section 5.03(e)
Certain Restrictions: Permitted Capital Expenditures

1. Items listed under Section 5.02(a) of the Purchaser Disclosure Schedule.
2. Items listed under Section 5.02(b) of the Purchaser Disclosure Schedule.

Section 5.03(i)
Certain Restrictions: Excluded Employees

Section 5.10
Credit Support

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]

[redacted]

Section 7.05
Governmental or Regulatory Approvals

1. FERC approval pursuant to Section 203 of the Federal Power Act.

2. Filings and approvals, including the expiration of applicable waiting periods, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

3. Consent of the Federal Communications Commission with respect to the change in beneficial ownership of Seller's radio license (*Call Sign: WPYT661)* used exclusively for the Facility.

4. Waiver of the FERC's capacity release requirements in Section 284.8 of FERC's regulations, and other related FERC policies and requirements, to facilitate the assignment and permanent release from Calpine Energy Services, L.P. to Duke Energy Florida, Inc. of a firm transportation capacity agreement on Gulfstream Natural Gas System, L.L.C., Contract Number 9006487.

5. FPSC approval pursuant to the Revised and Restated Settlement Agreement and other applicable statutes and FPSC rules.

Section 7.06
Third-Party Consents

[redacted]

1. [redacted]

2. [redacted]

3. [redacted]

[redacted]

4. [redacted]

5. [redacted]

Purchaser Disclosure Schedule

This Purchaser Disclosure Schedule (this "Purchaser Disclosure Schedule") has been prepared and delivered in accordance with the Asset Purchase and Sale Agreement, dated as of December 17, 2014 (the "Agreement"), by and between Duke Energy Florida, Inc., a Florida corporation ("Purchaser"), and Osprey Energy Center, LLC, a Delaware limited liability company ("Seller" or "Company"). Unless the context otherwise requires, capitalized terms used but not defined in this Purchaser Disclosure Schedule shall have the respective meanings assigned to such terms in the Agreement.

Purchaser may, at its option, include in the Purchaser Disclosure Schedule items that are not material, and any such inclusion, or any references to dollar amounts, shall not be deemed to be an acknowledgement or representation that such items are material, to establish any standard of materiality, to define further the meaning of such terms for purposes of the Agreement or to be deemed an admission by Purchaser that such item represents a material exception or fact, event or circumstance or that such item would reasonably be expected to have a Material Adverse Effect. Nothing in any section of this Purchaser Disclosure Schedule (i) shall be deemed to modify in any respect the standard of materiality or any other standard for disclosure set forth in the Agreement or (ii) relating to any possible breach or violation of any agreement, contract, applicable Law or any order of a Governmental Authority shall be construed as an admission or indication that any such breach or violation exists or has actually occurred.

The section headings and subheadings in this Purchaser Disclosure Schedule are for convenience of reference only and shall not be deemed to alter or affect the express descriptions of this Purchaser Disclosure Schedule and its sections as set forth in the Agreement.

Section 1.01(a)
Knowledge of Purchaser

1. John Burnett (Deputy General Counsel)
2. Matt Palasek (Director, Mergers & Acquisitions)
3. Kris Edmondson (GM Services – Florida)
4. Michael Rib (Generation and Regulatory Strategy Director)
5. Amy Dierolf (Manager EH&S)
6. Richard Jefferies (Director, Retirement)
7. Lawrence Valenti (Senior HR Analyst)

Section 4.03(c)
No Conflict, Violation or Breach

1. FERC approval pursuant to Section 203 of the Federal Power Act.

2. Filings and approvals, including the expiration of applicable waiting periods, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

3. FPSC approval pursuant to the Revised and Restated Settlement Agreement and other applicable statutes and FPSC rules.

4. Consent of the Federal Communications Commission with respect to the change in beneficial ownership of Seller's radio license (*Call Sign: WPYT661)* used exclusively for the Project.

5. Waiver of the FERC's capacity release requirements in Section 284.8 of FERC's regulations, and other related FERC policies and requirements, to facilitate the assignment and permanent release from Calpine Energy Services, L.P. to Duke Energy Florida, Inc. of a firm transportation capacity agreement on Gulfstream Natural Gas System, L.L.C., Contract Number 9006487.

Section 4.04
Required Governmental or Regulatory Approvals

1. Section 4.03(c) of this Purchaser Disclosure Schedule is incorporated herein by reference.

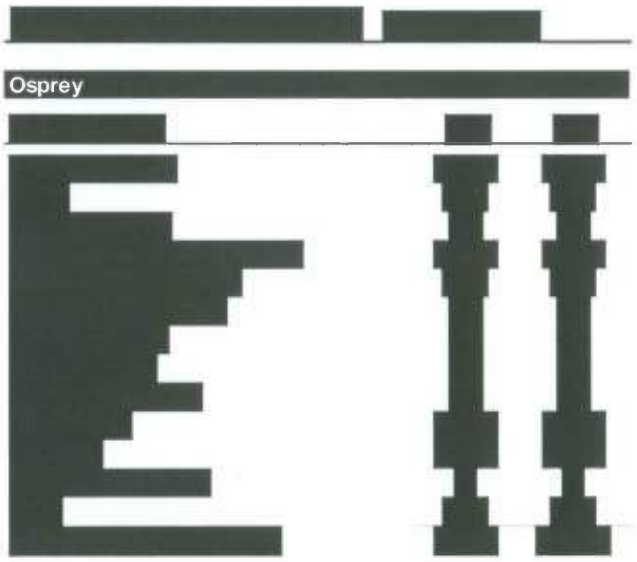
Section 5.02(a)
Conduct of Business

[redacted]

(a) [redacted]

(b) [redacted]

(c) [redacted]



(d)

(e)

(f)

(g)

(h)

(i) [redacted]

i. [redacted]

ii. [redacted]

iii. [redacted]

iv. [redacted]

Section 5.02(b)
Integration Activities

[redacted]

(a) [redacted]

(b) [redacted]

[redacted]

Section 6.05
Governmental or Regulatory Approvals

1. Section 4.03(c) of this Purchaser Disclosure Schedule is incorporated herein by reference.

Section 6.07
Third-Party Consents

[redacted]

1. [redacted]

2. [redacted]

3. [redacted]

[redacted]

4. [redacted]

5. [redacted]

Section 8.02(b)
Purchaser Excluded Knowledge Matters[1]

[redacted]

[1] Purchaser has been advised by Seller that while Seller agrees with the factual nature of this statement, the inclusion of this statement in the Purchaser Disclosure Schedule is not deemed an admission by Seller of any breach of the Agreement.

FORM OF ASSIGNMENT AND ASSUMPTION AGREEMENT

THIS ASSIGNMENT AND ASSUMPTION AGREEMENT (this "Agreement") is made as of [•], 201_ by and between OSPREY ENERGY CENTER, LLC, a Delaware limited liability company ("Osprey"), and DUKE ENERGY FLORIDA, INC., a Florida corporation ("DEF").

WITNESSETH:

WHEREAS, Osprey and DEF have entered into that certain Asset Purchase and Sale Agreement, dated as of December [•], 2014 (the "Purchase and Sale Agreement"), pursuant to which DEF has agreed to assume from Osprey, and covenant to pay, perform and discharge, the Assumed Liabilities.

NOW, THEREFORE, intending to be legally bound, and in consideration of the mutual covenants and agreements set forth herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

1. Assignment and Assumption. Pursuant to Section 2.03 of the Purchase and Sale Agreement, and subject to Section 2 hereof, Osprey hereby assigns to DEF all of DEF's right, title and interest in and to the Purchased Contracts (other than Purchased Contracts being assigned by CES), and DEF hereby assumes from Osprey and covenants to pay, perform and discharge, in a timely manner and in accordance with the terms thereof, all of the Assumed Liabilities, except the Assumed Liabilities arising out of Purchased Contracts which are in the name of Calpine Energy Services, L.P., a Delaware limited partnership ("CES") which are assigned by CES and assumed by DEF pursuant to a separate Assignment and Assumption Agreement, dated as of [•], 201_.

2. Terms of Purchase and Sale Agreement Control. Nothing contained in this Agreement shall in any way supersede, modify, replace, amend, rescind, waive, narrow or broaden any provision set forth in the Purchase and Sale Agreement or any of the rights, remedies or obligations arising therefrom. This Agreement shall in all ways be governed by, and subject to, the Purchase and Sale Agreement.

3. Miscellaneous. This Agreement (a) is executed pursuant to the Purchase and Sale Agreement and may be executed in multiple counterparts, each of which as so executed shall be deemed to be an original, but all of which together shall constitute one instrument, (b) shall be governed by and in accordance with the Laws of the State of New York applicable to a contract executed and performed in such State, without regard to the principles of conflicts of law thereof, and (c) shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns. Capitalized terms used herein without definition shall have the respective meanings assigned to them in the Purchase and Sale Agreement.

4. Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties to this Agreement may execute this Agreement by signing any such counterpart.

[Signatures Follow]

IN WITNESS WHEREOF, each party hereto has caused this Assignment and Assumption Agreement to be duly executed as of the date first written above.

OSPREY ENERGY CENTER, LLC

By: _____
Name: _____
Title: _____

DUKE ENERGY FLORIDA, INC.

By: _____
Name: _____
Title: _____

FORM OF ASSIGNMENT AND ASSUMPTION AGREEMENT

[CES]

THIS ASSIGNMENT AND ASSUMPTION AGREEMENT (this "Agreement") is made as of [•], 201__ by and between CALPINE ENERGY SERVICES, L.P., a Delaware limited partnership ("CES"), and DUKE ENERGY FLORIDA, INC., a Florida corporation ("DEF").

W I T N E S S E T H:

WHEREAS, Osprey Energy Center, LLC, a Delaware limited liability company ("Osprey") and an affiliate of CES, has entered into that certain Asset Purchase and Sale Agreement, dated as of [•], 2014 (the "Purchase and Sale Agreement"), by and between Osprey and DEF, the terms of which are incorporated herein by reference and which provides, among other things, for the sale, assignment and transfer by Osprey to DEF of the Purchased Contracts and the assumption by DEF of the Purchased Contracts; and

WHEREAS, in accordance with the terms of the Purchase and Sale Agreement, CES and DEF are entering into this Agreement, providing for (a) CES's assignment, transfer and delivery to DEF, of all of CES's right, title and interest in, under and to the Contracts set forth in Annex A attached hereto (collectively, the "CES Transferred Contracts"), (b) DEF's acceptance of such assignment, transfer and delivery and (c) DEF's assumption of CES's obligations and liabilities under the CES Transferred Contracts, arising from and after the date hereof, subject to the terms of the Purchase and Sale Agreement.

NOW, THEREFORE, in consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and subject to the terms and conditions of the Purchase and Sale Agreement, the parties hereto, intending to be legally bound hereby, agree as follows:

1. Assignment. In accordance with and subject to the terms of the Purchase and Sale Agreement, CES hereby assigns, transfers and delivers to DEF, all of CES's right, title and interest under the CES Transferred Contracts and DEF hereby assumes the Assumed Liabilities arising out of the CES Transferred Contracts.

2. Acceptance and Assumption. In accordance with and subject to the terms of the Purchase and Sale Agreement, DEF hereby assumes and agrees to pay, perform and discharge when due all of the Assumed Liabilities arising out of the CES Transferred Contracts.

2. Terms of Purchase and Sale Agreement Control. Nothing contained in this Agreement shall in any way supersede, modify, replace, amend, rescind, waive, narrow or broaden any provision set forth in the Purchase and Sale Agreement or any of the rights, remedies or obligations arising therefrom. This Agreement shall in all ways be governed by, and subject to, the Purchase and Sale Agreement.

3. Miscellaneous. This Agreement (a) is executed pursuant to the Purchase and Sale Agreement and may be executed in multiple counterparts, each of which as so executed shall be deemed to be an original, but all of which together shall constitute one instrument, (b) shall be governed by and in accordance with the Laws of the State of New York applicable to a contract executed and performed in such State, without regard to the principles of conflicts of law thereof, and (c) shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns. Capitalized terms used herein without definition shall have the respective meanings assigned to them in the Purchase and Sale Agreement.

4. Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties to this Agreement may execute this Agreement by signing any such counterpart.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the parties hereto have duly executed and delivered this Assignment and Assumption Agreement as of the date first written above.

CALPINE ENERGY SERVICES, L.P.

By: _____
Name:
Title:

DUKE ENERGY FLORIDA, INC.

By: _____
Name:
Title:

ANNEX A

1. Firm Transportation Service Agreement, dated July 18, 2003, by and between Gulfstream Natural Gas System, L.L.C., a Delaware limited liability company, and Calpine Energy Services, L.P., a Delaware limited partnership.

2. Amended and Restated Letter Agreement, dated January 6, 2005, effective November 1, 2003, by and between Gulfstream Natural Gas System, L.L.C., a Delaware limited liability company, and Calpine Energy Services, L.P., a Delaware limited partnership.

3. Letter Agreement regarding Agreed Creditworthiness Requirements, dated as of March 12, 2002, by and between Gulfstream Natural Gas System, L.L.C, a Delaware limited liability company and Calpine Energy Services, L.P., a Delaware limited partnership.

FORM OF BILL OF SALE AND ASSIGNMENT

This BILL OF SALE AND ASSIGNMENT (this "Bill of Sale"), dated as of [•], 201_, by OSPREY ENERGY CENTER, LLC, a Delaware limited liability company ("Osprey"), is made in favor of DUKE ENERGY FLORIDA, INC., a Florida corporation ("DEF").

WHEREAS, Osprey and DEF have entered into that certain Asset Purchase and Sale Agreement, dated as of December [•], 2014 (the "Purchase and Sale Agreement"), pursuant to which Osprey has agreed to convey to DEF the Purchased Assets.

1. Assignment. Pursuant to Section 2.01 of the Purchase and Sale Agreement, and subject to Section 2 hereof, for valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Osprey hereby sells, conveys, grants, assigns, transfers and delivers to DEF all of Osprey's right, title and interest in and to the Purchased Assets, free and clear of all Liens other than Permitted Liens, except (i) those Purchased Assets conveyed pursuant to the Special Warranty Deed by Osprey, as Grantor, and DEF, as Grantee, and dated as of [•], 201_, and (ii) those Purchased Contracts which are in the name of Calpine Energy Services, L.P., a Delaware limited partnership ("CES") which are assigned by CES and assumed by DEF pursuant to a separate Assignment and Assumption Agreement, dated as of [•], 201_.

2. Terms of Purchase and Sale Agreement Control. Nothing contained in this Bill of Sale shall in any way supersede, modify, replace, amend, rescind, waive, narrow or broaden any provision set forth in the Purchase and Sale Agreement or any of the rights, remedies or obligations arising therefrom. This Bill of Sale shall in all ways be governed by, and subject to, the Purchase and Sale Agreement.

3. Miscellaneous. This Bill of Sale (a) shall be governed by and in accordance with the Laws of the State of New York applicable to a contract executed and performed in such State, without regard to the principles of conflicts of law thereof, and (b) shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns. Capitalized terms used herein without definition shall have the respective meanings assigned to them in the Purchase and Sale Agreement.

4. Counterparts. This Bill of Sale may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties to this Bill of Sale may execute this Bill of Sale by signing any such counterpart.

[Signatures Follow]

IN WITNESS WHEREOF, the undersigned have caused this Bill of Sale to be duly executed as of the date first written above.

OSPREY ENERGY CENTER, LLC

By: _____
Name: _____
Title: _____

Accepted:

DUKE ENERGY FLORIDA, INC.

By: _____
Name: _____
Title: _____

[EXHIBIT C]

This instrument prepared by:

Tax Folio Number: 152825-000000-033010

FORM OF SPECIAL WARRANTY DEED

THIS SPECIAL WARRANTY DEED is made this __ day of _____, 20__, by OSPREY ENERGY CENTER, LLC, a Delaware limited liability company, whose address is c/o Calpine Corporation, 717 Texas Avenue, Suite 1000, Houston, Texas 77002, Attn: Chief Legal Office (the "Grantor") in favor of DUKE ENERGY FLORIDA, INC., a Florida corporation, whose address is c/o Duke Energy Florida, Inc., 299 First Avenue North, St. Petersburg, FL 33701, Attn: Chief Legal Office (the "Grantee").

W I T N E S S E T H :

That the Grantor, for and in consideration of the sum of Ten Dollars ($10) and other good and valuable consideration, to it in hand paid, the receipt whereof is hereby acknowledged, by these presents does grant, bargain, sell, alien, remise, release, convey and confirm unto the Grantee, its successors and assigns forever, all that certain parcel of land lying and being in the County of Polk, State of Florida, as more particularly described on **Exhibit "A"** hereto (the "Land").

SUBJECT, HOWEVER, TO THE FOLLOWING:

1. Real property taxes and assessments for the year 20__ and for subsequent years, which are not yet due and payable;
2. Zoning regulations and ordinances of applicable governmental and quasi-governmental agencies affecting the Land; and
3. The matters set forth on **Exhibit "B"** hereto, without any intention to reimpose same.

TOGETHER WITH all the tenements, hereditaments, and appurtenances thereto belonging or in anywise appertaining.

TO HAVE AND TO HOLD the above described Land, with the appurtenances, unto the said Grantee, its successors and assigns, in fee simple forever.

AND Grantor hereby covenants with said Grantee that it is lawfully seized of the Land hereby conveyed in fee simple; that it has good right and lawful authority to sell and convey said Land; that it hereby specially warrants the title to said Land and will defend the same against the lawful claims of any persons claiming by, through or under the said Grantor, but none others; provided that, Grantor makes no representation or warranty with respect to any portion of the Land that is included within any road right of way.

IN WITNESS WHEREOF, Grantor has caused these presents to be duly authorized in its name and by those thereunto duly authorized, the day and year first above written.

WITNESSED BY:

GRANTOR:

OSPREY ENERGY CENTER, LLC, a Delaware limited liability company

By:_____
Name:
Its:

_____
Name:_____

_____
Name:_____

STATE OF _____)
)ss:
COUNTY OF _____)

The foregoing instrument was acknowledged before me this ____ day of _____, 201_, by _____, as Chief Financial Officer of OSPREY ENERGY CENTER, LLC a Delaware limited liability company, on behalf of such entity, who is personally known to me or has produced a driver's license as identification.

_____
Notary Public, State of _____

_____
Printed Name of Notary Public

My Commission expires:

EXHIBIT "A"

Legal Description

The West ½ of the Northwest ¼ of the Northwest ¼ of Section 15, Township 28 South, Range 25 East, Polk County, Florida, less and except that certain property conveyed by Quit Claim deed recorded in deed book 972 page 357 and less and except that certain property conveyed by Quit Claim deed recorded in Official Records Book 666, page 640, and as modified by a Boundary Line Agreement recorded October 12, 2001 in Official Records Book 4822, Page 1799 and as amended by that certain First Amendment to Boundary Line Agreement recorded in Official Records Book 4837, Page 688 of the Public Records of Polk County, Florida.

EXHIBIT "B"

Permitted Exceptions

1. Easement in favor of City of Auburndale recorded in Official Records Book 3359 Page 1784, of the Public Records of Polk County, Florida.

2. Easement in favor of Gulfstream Natural Gas System, LLC recorded in Official Records Book 5054 Page 1057, of the Public Records of Polk County, Florida.

3. Easement in favor of Gulfstream Natural Gas System, LLC recorded in Official Records Book 5054 Page 1061, of the Public Records of Polk County, Florida.

4. Easement in favor of Auburndale Peaker Energy Center, L.L.C. recorded in Official Records Book 5421 Page 1177, of the Public Records of Polk County, Florida.

5. The terms, conditions and provisions of that certain Boundary Line Agreement recorded October 12, 2001 in Official Records Book 4822 Page 1799; as amended in Official Records Book 4837 Page 688, of the Public Records of Polk County, Florida.

6. The terms, provisions and conditions contained in that certain Ordinance No. 985, recorded in Official Records Book 4406, Page 1542, of the Public Records of Polk County, Florida.

FORM OF ESCROW AGREEMENT

THIS ESCROW AGREEMENT, dated as of [January 3, 2017][1] (this "Escrow Agreement"), is by and among OSPREY ENERGY CENTER, LLC, a Delaware limited liability company ("Seller"); DUKE ENERGY FLORIDA, INC., a Florida corporation ("Purchaser"); and [redacted]

RECITALS

A. Purchaser and Seller have entered into an Asset Purchase and Sale Agreement (the "Underlying Agreement"), dated as of December 17, 2014, pursuant to which Purchaser is purchasing Osprey Energy Center, a natural gas-fired combined-cycle generating facility in Auburndale, Florida, and associated assets and liabilities described in the Underlying Agreement. The Underlying Agreement provides that, simultaneously with the execution of this Escrow Agreement and the closing of the transactions contemplated under the Underlying Agreement, (a) Purchaser may, in accordance with the terms and conditions of the Underlying Agreement, deposit [redacted] (the "Indemnity Escrow Funds") in a segregated escrow account (the "Escrow Account A") to be held by Escrow Agent to satisfy certain indemnification obligations of Seller, and (b) Purchaser may, in accordance with the terms and conditions of the Underlying Agreement, deposit the Asset Repair Escrow Amount (the "Asset Repair Escrow Funds") in a segregated escrow account (the "Escrow Account B") to be held by Escrow Agent until certain disputes with respect to the Asset Repair Reduction Amount (as defined in the Underlying Agreement) are resolved in accordance with the terms and conditions of the Underlying Agreement.

B. Escrow Agent has agreed to accept, hold, and disburse the Escrow Funds deposited with it and the earnings thereon in accordance with the terms of this Escrow Agreement.

C. Purchaser and Seller have appointed the Representatives (as defined below) to represent them for all purposes in connection with Escrow Funds to be deposited with Escrow Agent and this Escrow Agreement.

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, for themselves, their successors and assigns, hereby agree as follows:

1. Definitions. The following terms shall have the following meanings when used herein:

"Asset Repair Escrow Amount" means [redacted]

"Asset Repair Escrow Period" shall mean the [redacted]

"Business Day" shall mean any day other than a Saturday, Sunday or any other day on which Escrow Agent located at the notice address set forth below is authorized or required by law or executive order to remain closed.

"Escrow Funds" shall mean the funds deposited with Escrow Agent pursuant to Section 3 of this Escrow Agreement, together with any interest and other income thereon.

[1] All dates in brackets to be adjusted if actual Closing is other than January 3, 2017.

"Indemnity Escrow Period" shall mean [redacted], unless extended by mutual agreement of Purchaser and Seller, in accordance with the terms and conditions of the Underlying Agreement.

"Joint Written Direction" shall mean a written direction executed by the Representatives and directing Escrow Agent to disburse all or a portion of the Escrow Funds or to take or refrain from taking any other action pursuant to this Escrow Agreement.

"Purchaser Representative" shall mean the person(s) so designated on Schedule D hereto or any other person designated in a writing signed by Purchaser and delivered to Escrow Agent and the Seller Representative in accordance with the notice provisions of this Escrow Agreement, to act as its representative under this Escrow Agreement.

"Representatives" shall mean the Purchaser Representative and the Seller Representative.

"Seller Representative" shall mean the person(s) so designated on Schedule D hereto or any other person designated in a writing signed by Seller and delivered to Escrow Agent and the Purchaser Representative in accordance with the notice provisions of this Escrow Agreement, to act as its representative under this Escrow Agreement.

2. Appointment of and Acceptance by Escrow Agent. Purchaser and Seller hereby appoint Escrow Agent to serve as escrow agent hereunder. Escrow Agent hereby accepts such appointment and, upon receipt by wire transfer of the Escrow Funds in accordance with Section 3 below, agrees to hold, invest and disburse the Escrow Funds in accordance with this Escrow Agreement.

3. Deposit of Escrow Funds. Simultaneously with the execution and delivery of this Escrow Agreement, and upon written notice to the Escrow Agent of Escrow Funds to be received Purchaser (a) will transfer the Indemnity Escrow Funds into Escrow Fund A, by wire transfer of immediately available funds, to an account designated by Escrow Agent as Escrow Fund A and/or (b) the Asset Repair Escrow Funds into Escrow Fund B, by wire transfer of immediately available funds, to an account designated by Escrow Agent as Escrow Fund B (collectively, the Indemnity Escrow Funds and the Asset Repair Escrow Funds, the "Escrow Funds"). In the event that only one Escrow Fund is funded, the provisions herein regarding the other Escrow Fund shall be disregarded. Escrow Agent shall be provided Joint Written Direction to terminate either of the unused Escrow Funds.

4. Disbursements of Escrow Funds. Escrow Agent shall disburse Escrow Funds at any time and from time to time, upon receipt of, and in accordance with, a Joint Written Direction. Escrow Agent shall disburse Indemnity Escrow Funds upon the expiration of the Indemnity Escrow Period as instructed in a Joint Written Direction, and the Asset Repair Escrow Funds upon the expiration of the Asset Repair Escrow Period as instructed in a Joint Written Direction, or earlier as instructed in a Joint Written Direction, from time to time, on the third Business Day after receipt of, and in accordance with, a Joint Written Direction. Each Joint Written Direction shall include directions to disburse funds identifying from which Escrow Fund to withdraw and in accordance with payment instructions set forth on Schedule A hereto, or if payment instructions are altered shall include complete payment instructions, including wiring instructions or an address to which a check shall be sent. Wire instructions shall include the receiving bank name and ABA number, beneficiary account name and number, and beneficiary street address (PO Box is not acceptable), and are subject to the optional security procedures set forth in Section 16 hereof. Prior to any disbursement, Escrow Agent shall have received reasonable identifying information regarding the recipient such that Escrow Agent may comply with its regulatory obligations and reasonable business practices, including without limitation a properly completed United States

Internal Revenue Service ("IRS") Form W-9 or original IRS Form W-8, as applicable. All disbursements of funds from the Escrow Funds shall be subject to the fees and claims of Escrow Agent and the Indemnified Parties pursuant to Section 10 and Section 11 below. Each of Purchaser and Seller agrees to issue the Joint Written Direction as and when Escrow Funds are required to be released in accordance with the Underlying Agreement.

5. Suspension of Performance; Disbursement into Court. If, at any time, (i) there shall exist any dispute between Purchaser, Seller or the Representatives with respect to the holding or disposition of all or any portion of the Escrow Funds or any other obligations of Escrow Agent hereunder, (ii) Escrow Agent is unable to determine, to Escrow Agent's sole satisfaction, the proper disposition of all or any portion of the Escrow Funds or Escrow Agent's proper actions with respect to its obligations hereunder, or (iii) the Representatives have not, within 10 calendar days of the furnishing by Escrow Agent of a notice of resignation pursuant to Section 7 hereof, appointed a successor Escrow Agent to act hereunder, then Escrow Agent may, in its sole reasonable discretion, take either or both of the following actions: (x) suspend the performance of any of its obligations (including without limitation any disbursement obligations) under this Escrow Agreement until such dispute or uncertainty shall be resolved to the sole satisfaction of Escrow Agent or until a successor Escrow Agent shall have been appointed, and/or (y) petition (by means of an interpleader action or any other appropriate method) any court of competent jurisdiction, in any venue convenient to Escrow Agent, for instructions with respect to such dispute or uncertainty, and to the extent required or permitted by law, pay into such court, for holding and disposition in accordance with the instructions of such court, all Escrow Funds, after deduction and payment to Escrow Agent of all fees and expenses (including court costs and reasonable attorneys' fees) payable to, incurred by, or expected to be incurred by Escrow Agent in connection with the performance of its duties and the exercise of its rights hereunder. Escrow Agent shall have no liability to Purchaser, Seller or the Representatives, their respective owners, shareholders or members or any other person with respect to any such suspension of performance or disbursement into court, specifically including any liability or claimed liability that may arise, or be alleged to have arisen, out of or as a result of any delay in the disbursement of the Escrow Funds or any delay in or with respect to any other action required or requested of Escrow Agent.

6. Investment of Funds. Based upon Purchaser's and Seller's prior review of investment alternatives, in the absence of further specific written direction to the contrary, Escrow Agent is directed to initially invest and reinvest the Escrow Funds in the investment indicated on Schedule B hereto. Purchaser and Seller may provide a Joint Written Direction to Escrow Agent changing the investment of the Escrow Funds; provided, however, that no investment or reinvestment may be made except in the following: (a) direct obligations of the United States of America or obligations the principal of and the interest on which are unconditionally guaranteed by the United State of America; (b) U.S. dollar denominated deposit accounts and certificates of deposits issued by a domestic bank (including Escrow Agent and its affiliates) which has a rating on its short-term deposits on the date of deposit or purchase of "A-1" or "A-l+" by S&P or "P-1" by Moody's and maturing no more than 360 days after the date of purchase (ratings on holding companies are not considered as the rating of the bank); or (c) institutional money market funds, including funds managed by Escrow Agent or any of its affiliates, in which case Purchaser and Seller acknowledge that they have received from Escrow Agent, either directly or via access to a relevant website, a current copy of the prospectus for the money market fund investment they have authorized; provided that Escrow Agent will not be directed to invest in investments that Escrow Agent in its sole discretion determines are not consistent with Escrow Agent's policy or practices. Purchaser and Seller acknowledge that Escrow Agent does not have a duty nor will it undertake any duty to provide investment advice.

All investments shall be made in the name of Escrow Agent. Notwithstanding anything to the contrary contained herein, Escrow Agent may, without notice to Purchaser and Seller, sell or liquidate any of the

foregoing investments at any time for any disbursement of Escrow Funds permitted or required hereunder. All investment earnings shall become part of the Escrow Funds and investment losses shall be charged against the Escrow Funds. Escrow Agent shall not be liable or responsible for loss in the value of any investment made pursuant to this Escrow Agreement, or for any loss, cost or penalty resulting from any sale or liquidation of the Escrow Funds. With respect to any Escrow Funds received by Escrow Agent after twelve o'clock, p.m., Central Standard Time, Escrow Agent shall not be required to invest such funds or to effect any investment instruction until the next day upon which banks in St. Paul, Minnesota and the New York Stock Exchange are open for business.

7. Resignation of Escrow Agent. Escrow Agent may resign and be discharged from the performance of its duties hereunder at any time by giving fifteen (15) calendar days prior written notice to the Purchaser and Seller specifying a date when such resignation shall take effect. Upon any such notice of resignation, Purchaser and Seller jointly shall appoint a successor Escrow Agent hereunder prior to the effective date of such resignation. If the Purchaser and Seller fail to appoint a successor Escrow Agent within such time, Escrow Agent shall have the right to petition a court of competent jurisdiction to appoint a successor Escrow Agent, and all costs and expenses (including without limitation reasonable attorneys' fees) related to such petition shall be paid jointly and severally by Purchaser and Seller. The resigning Escrow Agent shall transmit all records pertaining to the Escrow Funds and shall pay all Escrow Funds to the successor Escrow Agent, after making copies of such records as the resigning Escrow Agent deems advisable and after deduction and payment to the resigning Escrow Agent of all fees and expenses (including court costs and reasonable attorneys' fees) payable to, incurred by, or expected to be incurred by the resigning Escrow Agent in connection with the performance of its duties and the exercise of its rights hereunder. After any resigning Escrow Agent's resignation, the provisions of this Escrow Agreement shall inure to its benefit as to any actions taken or omitted to be taken by it while it was Escrow Agent under this Escrow Agreement.

8. Binding Effect; Successors. This Escrow Agreement shall be binding upon the respective parties hereto and their heirs, executors, successors or assigns. If Escrow Agent consolidates, merges or converts into, or transfers all or substantially all of its corporate trust business (including the escrow contemplated by this Escrow Agreement) to another corporation, the successor or transferee corporation without any further act shall be the successor Escrow Agent.

9. Liability of Escrow Agent. Escrow Agent undertakes to perform only such duties as are expressly set forth herein and no duties shall be implied. Escrow Agent has no fiduciary or discretionary duties of any kind. Escrow Agent shall have no liability under and no duty to inquire as to the provisions of any agreement other than this Escrow Agreement, including without limitation any other agreement between any or all of the parties hereto or any other persons even though reference thereto may be made herein. Escrow Agent shall not be liable for any action taken or omitted by it in good faith except to the extent that a court of competent jurisdiction determines that Escrow Agent's negligence or willful misconduct was the sole cause of any loss to the Purchaser or Seller. Escrow Agent's sole responsibility shall be for the safekeeping and disbursement of the Escrow Funds in accordance with the terms of this Escrow Agreement. Escrow Agent shall not be charged with knowledge or notice of any fact or circumstance not specifically set forth herein. Escrow Agent may rely upon any notice, instruction, request or other instrument, not only as to its due execution, validity and effectiveness, but also as to the truth and accuracy of any information contained therein, which Escrow Agent shall believe to be genuine and to have been signed or presented by the person or parties purporting to sign the same. In no event shall Escrow Agent be liable for incidental, indirect, special, consequential or punitive damages or penalties (including, but not limited to lost profits), even if Escrow Agent has been advised of the likelihood of such damages or penalty and regardless of the form of action. Escrow Agent shall not be responsible for delays or failures in performance resulting from acts beyond its control, including without limitation acts of God, strikes, lockouts, riots, acts of war or terror, epidemics, governmental regulations,

fire, communication line failures, computer viruses, power failures, earthquakes or other disasters. Escrow Agent shall not be obligated to take any legal action or commence any proceeding in connection with the Escrow Funds, any account in which Escrow Funds are deposited, this Escrow Agreement or the Underlying Agreement, or to appear in, prosecute or defend any such legal action or proceeding. Escrow Agent may consult legal counsel selected by it in the event of any dispute or question as to the construction of any of the provisions hereof or of any other agreement or of its duties hereunder, or relating to any dispute involving any party hereto, and shall incur no liability from any liability whatsoever in acting in accordance with the advice of such counsel. Purchaser and Seller, jointly and severally, shall promptly pay, upon demand, the reasonable fees and expenses of any such counsel. Purchaser and Seller agree to perform or procure the performance of all further acts and things, and execute and deliver such further documents, as may be required by law or as Escrow Agent may reasonably request in connection with its duties hereunder.

Escrow Agent is authorized, in its sole discretion, to comply with final orders issued or process entered by any court with respect to the Escrow Funds, without determination by Escrow Agent of such court's jurisdiction in the matter. If any portion of the Escrow Funds is at any time attached, garnished or levied upon under any court order, or in case the payment, assignment, transfer, conveyance or delivery of any such property shall be stayed or enjoined by any court order, or in case any order, judgment or decree shall be made or entered by any court affecting such property or any part thereof, then and in any such event, Escrow Agent is authorized, in its sole discretion, to rely upon and comply with any such order, writ, judgment or decree which it is advised by legal counsel selected by it is binding upon it without the need for appeal or other action; and if Escrow Agent complies with any such order, writ, judgment or decree, it shall not be liable to any of the parties hereto or to any other person or entity by reason of such compliance even though such order, writ, judgment or decree may be subsequently reversed, modified, annulled, set aside or vacated.

10. Indemnification of Escrow Agent. From and at all times after the date of this Escrow Agreement, Purchaser and Seller, jointly and severally, shall, to the fullest extent permitted by law, indemnify and hold harmless Escrow Agent and each director, officer, employee, attorney, agent and affiliate of Escrow Agent (collectively, the "Indemnified Parties") against any and all actions, claims (whether or not valid), losses, damages, liabilities, penalties, costs and expenses of any kind or nature (including without limitation reasonable attorneys' fees, costs and expenses) incurred by or asserted against any of the Indemnified Parties, whether direct, indirect or consequential, as a result of or arising from or in any way relating to any claim, demand, suit, action or proceeding (including any inquiry or investigation) by any person, including without limitation Purchaser, Seller and the Representatives, whether threatened or initiated, asserting a claim for any legal or equitable remedy arising from or in connection with the negotiation, preparation, execution, performance or failure of performance in connection with this Escrow Agreement or any transactions contemplated herein, whether or not any such Indemnified Party is a party to any such action, proceeding, suit or the target of any such inquiry or investigation; provided, however, that no Indemnified Party shall have the right to be indemnified hereunder for any liability finally determined by a court of competent jurisdiction, subject to no further appeal, to have resulted solely from the gross negligence or willful misconduct of such Indemnified Party. Purchaser and Seller further agree, jointly and severally, to indemnify each Indemnified Party for all costs, including without limitation reasonable attorney's fees, incurred by such Indemnified Party in connection with the enforcement of Purchaser's and Seller's indemnification obligations hereunder. Each Indemnified Party shall, with the consent of Purchaser and Seller (which shall not be unreasonably withheld, delayed or conditioned), have the right to select and employ separate counsel with respect to any action or claim brought or asserted against it, and the reasonable fees of such counsel shall be paid upon demand by the Purchaser and Seller jointly and severally. The obligations of Purchaser and Seller under this Section 11 shall survive any termination of this Escrow Agreement and the resignation or removal of Escrow Agent.

The parties agree that neither the payment by Purchaser or Seller of any claim by Escrow Agent for indemnification hereunder nor the disbursement of any amounts to Escrow Agent from the Escrow Funds in respect of a claim by Escrow Agent for indemnification shall impair, limit, modify, or affect, as between Purchaser and Seller, the respective rights and obligations of Purchaser and Seller under the Underlying Agreement.

11. Compensation of Escrow Agent. Purchaser and Seller agree to each pay one half of Escrow Agent's compensation for its services hereunder in accordance with Schedule C attached hereto, within 15 calendar days following receipt of an invoice for such compensation. The obligations of Purchaser and Seller under this Section 11 shall survive any termination of this Escrow Agreement and the resignation or removal of Escrow Agent. Escrow Agent is authorized to, and may disburse to itself from the Escrow Funds, from time to time, the amount of any compensation and reimbursement of out-of-pocket expenses due and payable hereunder if such amounts have not been timely paid (including any amount to which Escrow Agent or any Indemnified Party is entitled to seek indemnification hereunder). Escrow Agent shall notify Purchaser and Seller of any disbursement from the Escrow Funds to itself or any Indemnified Party in respect of any compensation or reimbursement hereunder and shall furnish Purchaser and Seller copies of related invoices and other statements. Seller, Purchaser and the Representatives hereby grant to Escrow Agent and the Indemnified Parties a security interest in, lien upon and right of offset against the Escrow Funds with respect to any compensation or reimbursement due any of them hereunder (including any claim for indemnification hereunder). If for any reason the Escrow Funds are insufficient to cover such compensation and reimbursement, Purchaser and Seller shall promptly pay such amounts to Escrow Agent or any Indemnified Party upon receipt of an itemized invoice. Notwithstanding anything in this Section 11, the obligations of Seller and Purchaser to each other or otherwise under the Underlying Agreement will not be reduced or modified by virtue of this Escrow Agreement, regardless of any rights of offset to Escrow Agent hereunder or otherwise.

12. Representations and Warranties. Purchaser and Seller each respectively make the following representations and warranties to Escrow Agent: (a) it has full power and authority to execute and deliver this Escrow Agreement and to perform its obligations hereunder; and this Escrow Agreement has been duly approved by all necessary action and constitutes its valid and binding agreement enforceable in accordance with its terms; and (b) each of the applicable persons designated on Schedule C attached hereto have been duly appointed to act as authorized representatives hereunder and individually have full power and authority to execute and deliver any Joint Written Direction, to amend, modify or waive any provision of this Escrow Agreement and to take any and all other actions as authorized representatives under this Escrow Agreement, all without further consent or direction from, or notice to, it or any other party, provided that any change in designation of such authorized representatives shall be provided by written notice delivered to each party to this Escrow Agreement.

13. Identifying Information. To help the government fight the funding of terrorism and money laundering activities, Federal law requires all financial institutions to obtain, verify, and record information that identifies each person who opens an account. For a non-individual person such as a business entity, a charity, a trust, or other legal entity, Escrow Agent requires documentation to verify its formation and existence as a legal entity. Escrow Agent may ask to see financial statements, licenses, identification and authorization documents from individuals claiming authority to represent the entity or other relevant documentation. The parties acknowledge that a portion of the identifying information set forth herein is being requested by Escrow Agent in connection with the USA Patriot Act, Pub.L.107-56 (the "Act"), and each agrees to provide any additional information requested by Escrow Agent in connection with the Act or any other legislation or regulation to which Escrow Agent is subject, in a timely manner.

14. Consent to Jurisdiction and Venue; Governing Law. In the event that any party hereto commences a lawsuit or other proceeding relating to or arising from this Escrow Agreement, the parties hereto agree to exclusive personal jurisdiction by and venue in the state and federal courts in the Borough of Manhattan, County of New York in the State of New York and waive any objection to such jurisdiction or venue. The parties hereto consent to and agree to exclusively submit to the jurisdiction of such courts specified herein and agree to accept service of process to vest personal jurisdiction over them in any of these courts. This Escrow Agreement shall be construed and interpreted in accordance with the internal laws of the State of New York without giving effect to the conflict of laws principles thereof.

15. Notices. All notices, approvals, consents, requests, and other communications hereunder shall be in writing and shall be delivered (i) by personal delivery, or (ii) by national overnight courier service, or (iii) by certified or registered mail, return receipt requested, or (iv) via facsimile transmission, with confirmed receipt or (v) via email by way of a PDF attachment thereto of an executed document. Notice shall be effective upon receipt except for notice via email, which shall be effective only when the recipient, by return email or notice delivered by other method provided for in this Section 15, acknowledges having received that email (with an automatic "read receipt" or similar notice not constituting an acknowledgement of an email receipt for purposes of this Section 15). Such notices shall be sent to the applicable party or parties at the address specified below:

If to Purchaser or Purchaser Representative at:

Duke Energy Florida, Inc.
299 First Avenue North
St. Petersburg, FL 33701
Attn: John Burnett
Facsimile No.: (727) 820-5041
Email: john.burnett@duke-energy.com

with a copy to (which shall not constitute notice):

Duke Energy Corporation
550 S. Tryon Street, DEC
Charlotte, North Carolina 28202
Attn: Greer Mendelow, Esq.
Facsimile No.: (980) 373-8534
Email: greer.mendelow@duke-energy.com

and

Parker Poe Adams & Bernstein LLP
401 S. Tryon Street, Suite 3000
Charlotte, North Carolina 28202
Attention: Roy L. Smart, III
Facsimile No.: (704) 334-4706
Email: skipsmart@parkerpoe.com

If to Seller or Seller Representative at:

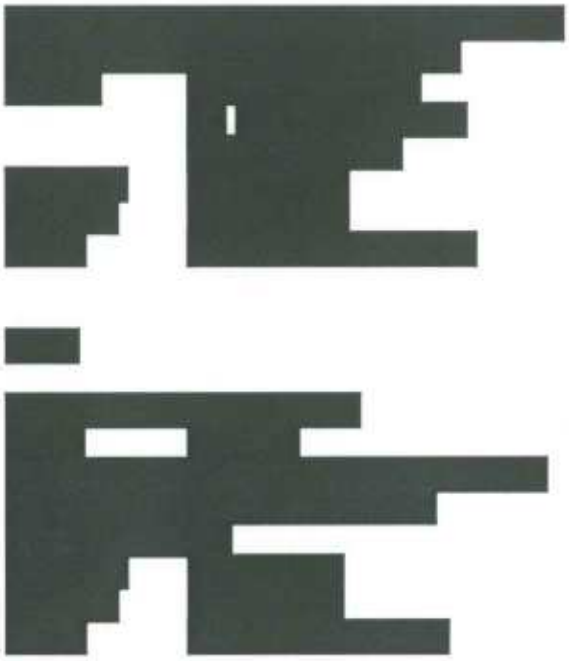
OSPREY ENERGY CENTER, LLC
c/o Calpine Corporation

717 Texas Avenue, Suite 1000
Houston, TX 77002
Attention: Chief Legal Officer
Facsimile No.: (713) 830-8751 or (832) 325-1508
Telephone No:
Email:

with a copy to (which shall not constitute notice):

White & Case LLP
1155 Avenue of the Americas
New York, NY 10036-2787
Attention: Michael S. Shenberg
Facsimile No.: (212) 354-8113
Email: mshenberg@whitecase.com

If to Escrow Agent at:



or to such other address as each party may designate for itself by like notice and unless otherwise provided herein shall be deemed to have been given on the date received.

16. Optional Security Procedures. In the event funds transfer instructions, address changes or change in contact information are given (other than in writing at the time of execution of this Escrow Agreement), whether in writing, by facsimile or otherwise, Escrow Agent is authorized but shall be under no duty to seek confirmation of such instructions by telephone call-back to the Representative(s) designated on Schedule D hereto, and Escrow Agent may rely upon the confirmation of anyone purporting to be the Representative(s) so designated. The persons and telephone numbers for call-backs may be changed only in writing actually received and acknowledged by Escrow Agent and shall be effective only after Escrow Agent has a reasonable opportunity to act on such changes. If Escrow Agent is unable to contact any of the designated Representatives identified in Schedule D, Escrow Agent is hereby authorized but shall be under no duty to seek confirmation of such instructions by telephone call-back to any one or more of Purchaser or Seller's executive officers, as the case may be, which shall include the

titles of Chief Executive Officer, President and Vice President ("Executive Officers"), as Escrow Agent may select. Such Executive Officer shall deliver to Escrow Agent a fully executed incumbency certificate, and Escrow Agent may rely upon the confirmation of anyone purporting to be any such officer. Purchaser and Seller agree that Escrow Agent may at its option record any telephone calls made pursuant to this Section 16. Escrow Agent in any Escrow Funds transfer may rely solely upon any account numbers or similar identifying numbers provided by Purchaser or Seller to identify (a) the beneficiary, (b) the beneficiary's bank, or (c) an intermediary bank. Escrow Agent may apply any of the Escrow Funds for any payment order it executes using any such identifying number, even when its use may result in a person other than the beneficiary being paid, or the transfer of funds to a bank other than the beneficiary's bank or an intermediary bank designated. Purchaser and Seller acknowledge that these optional security procedures are commercially reasonable.

17. Amendment, Waiver and Assignment. None of the terms or conditions of this Escrow Agreement may be changed, waived, modified, discharged, terminated or varied unless in writing duly signed by each party to this Escrow Agreement. No course of conduct shall constitute a waiver of any of the terms and conditions of this Escrow Agreement, unless such waiver is specified in writing, and then only to the extent so specified. A waiver of any of the terms and conditions of this Escrow Agreement on one occasion shall not constitute a waiver of the other terms of this Escrow Agreement, or of such terms and conditions on any other occasion. Except as provided in Section 8 hereof, this Escrow Agreement may not be assigned by any party without the written consent of the other parties.

18. Severability. To the extent any provision of this Escrow Agreement is prohibited by or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Escrow Agreement.

19. Entire Agreement; No Third Party Beneficiaries. This Escrow Agreement constitutes the entire agreement between the parties relating to holding, investment and disbursement of Escrow Funds and sets forth in their entirety the obligations and duties of Escrow Agent. Nothing in this Escrow Agreement, express or implied, is intended to or shall confer upon any other person any right, benefit or remedy of any nature whatsoever under or by reason of this Escrow Agreement.

20. Execution in Counterparts; Facsimiles. This Escrow Agreement and any Joint Written Direction may be executed in two or more counterparts, which when so executed shall constitute one and the same agreement or direction. The delivery of copies of this Escrow Agreement and any Joint Written Instruction and their respective signature pages by PDF or facsimile transmission shall constitute effective execution and delivery as to the parties and may be used in lieu of originals for all purposes.

21. Termination. This Escrow Agreement shall terminate upon the distribution of all Escrow Funds pursuant to any applicable provision hereof, and Escrow Agent shall thereafter have no further obligation or liability with respect to this Escrow Agreement or the Escrow Funds.

22. Dealings. Escrow Agent and any stockholder, director, officer or employee of Escrow Agent may buy, sell, and deal in any of the securities of the Purchaser or Seller and become pecuniarily interested in any transaction in which the Purchaser or Seller may be interested, and contract and lend money to the Purchaser or Seller and otherwise act as fully and freely as though it were not Escrow Agent under this Escrow Agreement. Nothing herein shall preclude Escrow Agent from acting in any other capacity for the Purchaser or Seller or for any other entity; provided that Escrow Agent shall provide Seller or Purchaser, as applicable, with reasonable advance notice of acting in such other capacity.

23. Brokerage Confirmation Waiver; Shareholder Communications. Purchaser and Seller

acknowledge that to the extent regulations of the Comptroller of the Currency or other applicable regulatory entity grant either the right to receive brokerage confirmations for certain security transactions as they occur, Purchaser and Seller specifically waive receipt of such confirmations to the extent permitted by law. Escrow Agent will furnish the Purchaser and Seller periodic cash transaction statements that include detail for all investment transactions made by Escrow Agent. The Shareholder Communications Act of 1985 and its regulations require that banks and trust companies make an effort to facilitate communication between registrants of U.S. securities and the parties who have the authority to vote or direct the voting of those securities regarding proxy dissemination and other corporate communications. Unless the parties hereto object in writing, Escrow Agent will provide the obligatory information to the registrant upon request. Such objection will apply to all securities held as Escrow Funds now and in the future unless Escrow Agent is notified in writing.

24. Tax Reporting. Escrow Agent shall have no responsibility for the tax consequences of this Escrow Agreement and Purchaser and Seller shall consult with independent counsel concerning any and all tax matters. Purchaser and Seller shall provide Escrow Agent Form W-9 and an original Form W-8, as applicable, for each payee, together with any other documentation and information requested by Escrow Agent in connection with Escrow Agent's reporting obligations under applicable IRS regulations. If such tax documentation is not so provided, Escrow Agent shall withhold taxes as required by the IRS. Seller and Purchaser have determined that any interest or income on Escrow Funds shall be reported on an accrual basis and deemed to be for the account of Seller. Purchaser and Seller shall prepare and file all required tax filings with the IRS and any other applicable taxing authority; provided that the parties further agree that:

(a) Escrow Agent IRS Reporting. Purchaser and Seller shall provide Escrow Agent with all information requested by Escrow Agent in connection with the preparation of all applicable Form 1099 and Form 1042-S documents with respect to all distributions as well as in the performance of Escrow Agent's reporting obligations under the Foreign Account Tax Compliance Act and Foreign Investment in Real Property Tax Act or other applicable law or regulation.

(b) Withholding Requests and Indemnification. Purchaser and Seller jointly and severally agree to (i) assume all obligations imposed now or hereafter by any applicable tax law or regulation with respect to payments or performance under this Escrow Agreement, (ii) request Escrow Agent in writing with respect to withholding and other taxes, assessments or other governmental charges, and advise Escrow Agent in writing with respect to any certifications and governmental reporting that may be required under any applicable laws or regulations, and (iii) indemnify and hold Escrow Agent harmless pursuant to Section 10 hereof from any liability or obligation on account of taxes, assessments, additions for late payment, interest, penalties, expenses and other governmental charges that may be assessed or asserted against Escrow Agent.

(c) Imputed Interest. To the extent that IRS imputed interest regulations apply, Purchaser and Seller shall so inform Escrow Agent, provide Escrow Agent with all imputed interest calculations and direct Escrow Agent to disburse imputed interest amounts as Purchaser and Seller deem appropriate. Escrow Agent shall rely solely on such provided calculations and information and shall have no responsibility for the accuracy or completeness of any such calculations or information.

25. WAIVER OF TRIAL BY JURY. EACH PARTY TO THIS ESCROW AGREEMENT HEREBY WAIVES ANY RIGHT THAT IT MAY HAVE TO A TRIAL BY JURY ON ANY CLAIM, COUNTERCLAIM, SETOFF, DEMAND, ACTION OR CAUSE OF ACTION (1) ARISING OUT OF OR IN ANY WAY RELATED TO THIS ESCROW AGREEMENT OR (2) IN ANY WAY IN CONNECTION WITH OR PERTAINING OR RELATED TO OR INCIDENTAL TO ANY DEALINGS OF THE PARTIES TO THIS ESCROW AGREEMENT OR IN CONNECTION WITH THIS ESCROW

AGREEMENT OR THE EXERCISE OF ANY SUCH PARTY'S RIGHTS AND REMEDIES UNDER THIS ESCROW AGREEMENT OR THE CONDUCT OR THE RELATIONSHIP OF THE PARTIES TO THIS ESCROW AGREEMENT, IN ALL OF THE FOREGOING CASES WHETHER NOW EXISTING OR HEREAFTER ARISING AND WHETHER IN CONTRACT, TORT OR OTHERWISE. EACH OF THE PARTIES HERETO HEREBY FURTHER ACKNOWLEDGES AND AGREES THAT EACH HAS REVIEWED OR HAD THE OPPORTUNITY TO REVIEW THIS WAIVER WITH ITS RESPECTIVE LEGAL COUNSEL, AND THAT IT KNOWINGLY AND VOLUNTARILY WAIVES ITS JURY TRIAL RIGHTS FOLLOWING CONSULTATION WITH SUCH LEGAL COUNSEL. IN THE EVENT OF LITIGATION, THIS ESCROW AGREEMENT MAY BE FILED AS A CONSENT BY ALL PARTIES TO A TRIAL BY THE COURT.

26. Publicity. No party will (a) use any other party's proprietary indicia, trademarks, service marks, trade names, logos, symbols, or brand names, or (b) otherwise refer to or identify any other party in advertising, publicity releases, or promotional or marketing publications, or correspondence to third parties without, in each case, securing the prior written consent of such other party.

[*signature page follows*]

IN WITNESS WHEREOF, the parties hereto have caused this Escrow Agreement to be executed under seal as of the date first above written.

OSPREY ENERGY CENTER, LLC

By: _____
Name: _____
Title: _____

DUKE ENERGY FLORIDA, INC.

By: _____
Name: _____
Title: _____

SCHEDULE A

Payment Instructions

Payment Instructions for Disbursements to Purchaser:

Payment Instructions, including: • Receiving bank name • Receiving bank ABA number • Beneficiary account number • Beneficiary account name • Beneficiary street address (PO Box is not acceptable)	Reference/Comment

Payment Instructions for Disbursements to Seller:

Payment Instructions, including: • Receiving bank name • Receiving bank ABA number • Beneficiary account number • Beneficiary account name • Beneficiary street address (PO Box is not acceptable)	Reference/Comment

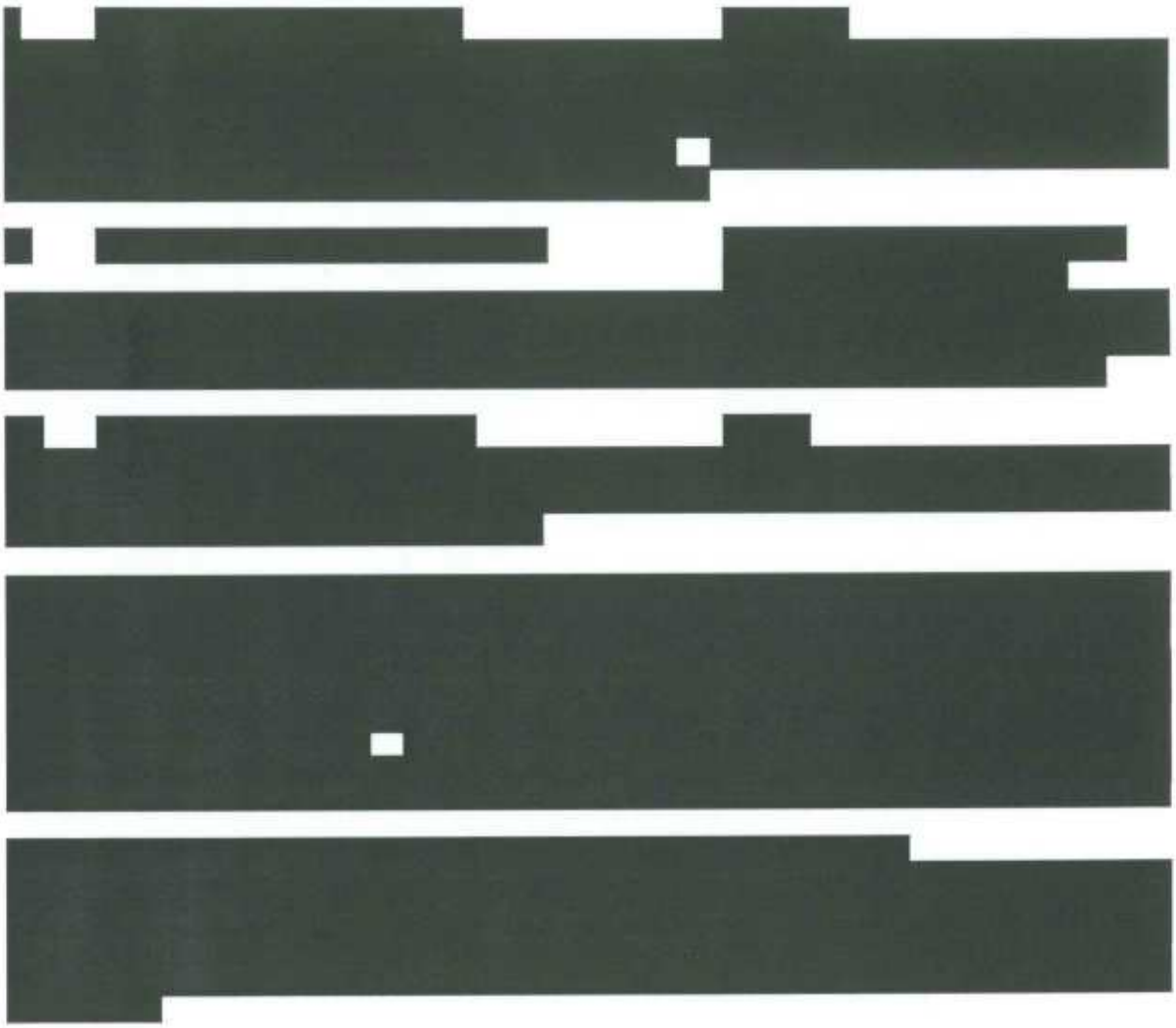
SCHEDULE B

Investment Authorization

[redacted]

SCHEDULE C

Schedule of Fees for Services as Escrow Agent



SCHEDULE D

Purchaser:

Each of the following person(s) is a **Purchaser Representative** authorized to execute documents and direct Escrow Agent as to all matters, including fund transfers, address changes and contact information changes, on Purchaser's behalf (only one signature required):

Name	Specimen signature	Telephone No.
Name	Specimen signature	Telephone No
Name	Specimen signature	Telephone No

(Note: if only one person is identified above, please add the following language:)
The following person not listed above is authorized for call-back confirmations:

[_____]
Name _____ Telephone Number

Seller:

Each of the following person(s) is a **Seller Representative** authorized to execute documents and direct Escrow Agent as to all matters, including fund transfers, address changes and contact information changes, on Seller's behalf (only one signature required):

Name	Specimen signature	Telephone No
Name	Specimen signature	Telephone No
Name	Specimen signature	Telephone No

(Note: if only one person is identified above, please add the following language:)
The following person not listed above is authorized for call-back confirmations

[_____]
Name _____ Telephone Number

IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____

DATE: _____, 201_

BENEFICIARY: **APPLICANT:**

LADIES AND GENTLEMEN:

AT THE REQUEST AND FOR THE ACCOUNT OF _____ (THE "APPLICANT"), (ADDRESS), AND ON BEHALF OF _____(THE "ACCOUNT PARTY") WE, _____ (THE "ISSUER"), HEREBY ESTABLISH, EFFECTIVE IMMEDIATELY, IN FAVOR OF _____(THE "BENEFICIARY") OUR IRREVOCABLE STANDBY LETTER OF CREDIT NO. (THIS "LETTER OF CREDIT") IN THE AGGREGATE AMOUNT OF [redacted]
(AS SUCH AMOUNT MAY BE REDUCED FROM TIME TO TIME BY PARTIAL DRAWS HEREUNDER, THE "STATED AMOUNT").

THIS LETTER OF CREDIT IS ISSUED, PRESENTABLE AND PAYABLE AT THE ISSUER'S OFFICE LOCATED AT _____ ATTENTION: STANDBY LETTER OF CREDIT SECTION, AND EXPIRES WITH ITS CLOSE OF BUSINESS ON _____ [redacted] (THE "EXPIRATION DATE")

FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO THE BENEFICIARY BY PAYMENT AGAINST PRESENTATION AT THE ISSUER'S OFFICE AS STIPULATED HEREIN ABOVE, OF THE BENEFICIARY'S SIGNED AND APPROPRIATELY COMPLETED SIGHT DRAFT IN THE FORM OF EXHIBIT 1 HERETO, THE BENEFICIARY'S SIGNED AND APPROPRIATELY COMPLETED DRAWING CERTIFICATE IN THE FORM OF EXHIBIT 2 HERETO AND A COPY OF THIS ORIGINAL LETTER OF CREDIT AND AMENDMENTS (IF ANY).

IF A DRAWING IN COMPLIANCE WITH THE TERMS AND CONDITIONS HEREOF IS PRESENTED AT THE ADDRESS SPECIFIED ABOVE OR DELIVERED TO US BY OVERNIGHT COURIER AT OR PRIOR TO 11:00 A.M. **EASTERN TIME** ON A BUSINESS DAY, PAYMENT OF THE AMOUNT SPECIFIED IN SUCH DRAFT WILL BE MADE ON THE THIRD SUCCEEDING BUSINESS DAY. IF SUCH DRAWING IS SO PRESENTED AFTER 11:00 A.M. **EASTERN TIME** ON A BUSINESS DAY, PAYMENT OF THE AMOUNT SPECIFIED IN SUCH DRAFT WILL BE MADE ON THE FOURTH SUCCEEDING BUSINESS DAY.

PARTIAL AND MULTIPLE DRAWINGS ARE PERMITTED HEREUNDER. ANY DRAWING HONORED HEREUNDER BY THE ISSUER SHALL REDUCE THE STATED AMOUNT AVAILABLE FOR DRAWINGS BY THE AMOUNT OF SUCH DRAWING.

ALL BANKING CHARGES ASSOCIATED WITH THIS LETTER OF CREDIT ARE FOR THE ACCOUNT OF THE APPLICANT.

AS USED HEREIN, "BUSINESS DAY" MEANS ANY DAY OTHER THAN SATURDAY, SUNDAY OR A DAY ON WHICH COMMERCIAL BANKS IN NEW YORK, NEW YORK ARE AUTHORIZED OR REQUIRED TO CLOSE.

THIS LETTER OF CREDIT IS SUBJECT TO AND GOVERNED BY THE INTERNATIONAL STANDBY PRACTICES, INTERNATIONAL CHAMBER OF COMMERCE (ICC) PUBLICATION NO. 590 ("ISP98"). AS TO MATTERS NOT ADDRESSED BY THE ISP98, AND TO THE EXTENT NOT INCONSISTENT WITH THE ISP98, THIS LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE

WITH THE LAW OF THE STATE OF NEW YORK (INCLUDING, WITHOUT LIMITATION, ARTICLE 5 OF THE UNIFORM COMMERCIAL CODE OF THE STATE OF NEW YORK).

THIS LETTER OF CREDIT SETS FORTH IN FULL THE TERMS OF OUR UNDERTAKING AND SUCH UNDERTAKING SHALL NOT IN ANY WAY BE MODIFIED, AMENDED OR AMPLIFIED BY REASON OF OUR REFERENCE TO ANY AGREEMENTS OR INSTRUMENT REFERRED TO HEREIN OR IN WHICH THIS LETTER OF CREDIT IS REFERRED TO. ANY SUCH AGREEMENTS OR INSTRUMENT SHALL NOT BE DEEMED INCORPORATED HEREIN BY REFERENCE.

SINCERELY,

NAME: _____

TITLE: _____

EXHIBIT 1

[BENEFICIARY LETTERHEAD]

SIGHT DRAFT

[DATE]

BANK
DEPARTMENT
ADDRESS STREET
CITY, STATE ZIP
ATTENTION: STANDBY LETTER OF CREDIT SECTION

RE: IRREVOCABLE STANDBY LETTER OF CREDIT NUMBER _____

FOR VALUE RECEIVED, PAY TO THE ORDER OF _____ BY WIRE TRANSFER OF IMMEDIATELY AVAILABLE FUNDS TO THE FOLLOWING ACCOUNT:

[NAME OF ACCOUNT]
[ACCOUNT NUMBER]
[NAME AND ADDRESS OF BANK AT WHICH ACCOUNT IS MAINTAINED]
[ABA NUMBER]
[REFERENCE]

THE FOLLOWING AMOUNT:

[INSERT NUMBER OF DOLLARS IN WRITING] UNITED STATES DOLLARS
(US$ [INSERT NUMBER OF DOLLARS IN FIGURES])

DRAWN UPON YOUR IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ DATED _____, 20__

BY: _____

NAME: _____

TITLE: _____

EXHIBIT 2

DRAWING CERTIFICATE

[DATE]

BANK
DEPARTMENT
ADDRESS STREET
CITY, STATE ZIP
ATTENTION: STANDBY LETTER OF CREDIT SECTION

RE: IRREVOCABLE STANDBY LETTER OF CREDIT NUMBER _____

LADIES AND GENTLEMEN:

THE UNDERSIGNED, A DULY AUTHORIZED OFFICER OF _____, THE BENEFICIARY (THE "BENEFICIARY") OF THE ABOVE CAPTIONED LETTER OF CREDIT (THE "LETTER OF CREDIT"), HEREBY CERTIFIES TO _____ (THE "ISSUER") WITH RESPECT TO THE LETTER OF CREDIT THAT:

(1)

(A) _____ (THE "ACCOUNT PARTY") IS IN BREACH OF ITS INDEMNIFICATION OBLIGATIONS UNDER SECTION 8.02(a)(i) OF THAT CERTAIN ASSET PURCHASE AND SALE AGREEMENT DATED AS OF _____, 2014 BETWEEN THE ACCOUNT PARTY AND THE BENEFICIARY (THE "AGREEMENT"), ; AND

(B) THE AMOUNT BEING DRAWN PURSUANT TO THIS CERTIFICATE IS AN AMOUNT THAT IS DUE AND OWING TO BENEFICIARY UNDER THE AGREEMENT AND REMAINS UNPAID AT THE TIME OF THIS DRAWING.

OR

(2) THE LETTER OF CREDIT HAS NOT BEEN REPLACED AS REQUIRED BY THE AGREEMENT.

DEFINED TERMS USED IN THIS DRAWING CERTIFICATE AND NOT OTHERWISE DEFINED HEREIN SHALL HAVE THE MEANING ASCRIBED TO SUCH TERMS IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THE UNDERSIGNED HAS EXECUTED THIS DRAWING CERTIFICATE ON THIS _____ DAY OF _____ 20___.

BY: _____

NAME: _____

TITLE: _____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. _____
Submitted for filing:
May 27, 2014

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

JOHN T. BURNETT
Deputy General Counsel
DIANNE M. TRIPLETT
Associate General Counsel
DUKE ENERGY FLORIDA, INC.
299 1st Avenue North
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

JAMES MICHAEL WALLS
Florida Bar No. 706272
BLAISE N. GAMBA
Florida Bar No. 027942
CARLTON FIELDS JORDEN BURT, P.A.
4221 W. Boy Scout Blvd., Ste.1000
Tampa, Florida 33607
Telephone: (813) 223-7000
Facsimile: (813) 229-4133

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 15
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch

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

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. _____

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the

Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the Director, IRP & Analytics – Florida, I oversaw the completion of the Company's most recent TYSP document filed in April 2014 and the Company's 2013 TYSP. I was also responsible for the Company's evaluation of options to meet its needs for reliable electric power prior to 2018.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009 I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy accepted my current position. Prior to joining Progress Energy, I was employed for more than 5 years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas fired power plant projects in nine states. I was also employed for more than 8 years as an environmental consultant with projects including development, permitting and compliance of

power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of the Company in support of its Petition for Determination of Cost Effective Alternative to Meet Need prior to 2018 for Duke Energy Florida. I will provide an overview of the generation alternatives that the Company proposes to build to meet its need prior to 2018 in the most cost-effective manner for its customers. I will discuss the resource planning process and how that led the Company to identify this need prior to 2018 and I will explain the steps the Company took to identify available, potentially superior supply-side alternatives. Next, I will explain the Company's evaluation of these generation alternatives and set forth the reasons why the Company's self-build generation options are the most cost-effective resource options to meet the Company's need prior to 2018. I will conclude my testimony by explaining the Company's decision to proceed with its self-build generation options to meet its need prior to 2018 in the most cost-effective manner for the Company's customers.

Q. Are you sponsoring any exhibits to your testimony?

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

- Exhibit No. ___ (BMHB-1), a copy of the Florida Reliability Coordinating Council ("FRCC") Evaluation of Transmission Impact of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") --- Transmission Impact Study for Shutdown of Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") with retirement of Crystal River Unit 3 ("MATS Study");
- Exhibit No. ___ (BMHB-2), the Company's current, April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), the Company's near-term summer and winter load forecast;
- Exhibit No. ___ (BMHB-4), the Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-5), the Company's forecast of physical and dispatchable demand-side resource reserves through the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-6), the generation options evaluated to contribute to the Company's capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-7), a confidential chart of the supply-side generation proposals evaluated by the Company to meet its capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-8), the Company's initial detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summers of 2016 and 2017;

- Exhibit No. ___ (BMHB-9), the Company's cost sensitivity analysis results based on the initial detailed economic analysis;
- Exhibit No. ___ (BMHB-10), the Company's final detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summer of 2016 and 2017; and
- Exhibit No. ___ (BMHB-11), the Company's analysis of natural gas price and carbon cost ("CO2") sensitivities to the final detailed economic analyses.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively, to meet its 20 percent Reserve Margin commitment and to serve its customers' future electrical power needs in a reliable and cost-effective manner. Faced with generation plant retirements and additional customer and peak load demand, the Company determined in its resource planning process that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were superior to any other alternative, including additional renewable energy resources and conservation measures, to meet the Company's near-term generation capacity needs.

The Company further evaluated these projects against power purchase agreement and generation facility acquisition proposals from third-party generators, and none of these proposals compared more favorably, on a

quantitative and qualitative basis, to the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. DEF has demonstrated that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the best alternatives for maintaining DEF's electric system reliability and integrity, and providing its customers with adequate electricity at a reasonable cost, by the summer of 2016 and 2017, respectively. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

III. OVERVIEW OF THE COMPANY'S NEED AND PETITION.

Q. Can you generally explain the Company's need that led to this Petition?

A. Yes. The Company faced resource planning decisions leading up to and early in 2013 that affected the Company's near-term need in the ten-year planning period for generation capacity to meet customer energy needs. As a result, during the Company's annual integrated resource planning analysis, the Company identified substantial generation capacity needs in the near term, beginning in 2016. This analysis was first reflected in the Company's 2013 TYSP. The Company's continuing resource planning process and analysis that resulted in its 2014 TYSP confirmed this need beginning in 2016.

Q. What were these resource planning decisions?

A. In February 2013, the Company decided to retire its Crystal River Unit 3 nuclear power plant ("CR3"). The Company also decided to retire its CR1 and CR2 (also "CRS" for "Crystal River South"), coal plants earlier than originally planned. These generation retirements account for over 1,500 MegaWatts ("MW") of summer generation capacity on DEF's system.

The Company planned to retire its CR1 and CR2 coal plants in 2020. The issuance of new EPA environmental regulations under the Clean Air Act affected the Company's planned retirement of CR1 and CR2. As a result of these new environmental regulations, the Company faced the retirement of CR1 and CR2 as soon as 2015, but, as explained in more detail below, the Company now plans to retire CR1 and CR2 in 2018. Still, these and other retirement decisions and the Company's response to them, coupled with the Company's load growth, create a near term need for generation, commencing in 2016.

Q. What were the environmental regulations that impacted the Company's planned retirement of its Crystal River South coal plants?

A. The EPA issued its MATS regulations in December 2011 and these regulations became effective in April 2012. The EPA MATS regulations are designed to reduce mercury, other metals, and acid gas emissions from coal- and oil-fired power plants. Compliance with MATS is required three years after the effective date, or by April 2015. A one-year MATS compliance extension is available under certain conditions from the Florida Department of Environmental

Protection ("FDEP"). The Crystal River Units 1 and 2 coal-fired units cannot meet the emissions requirements for MATS as currently configured and without changes in the coal fuel source for the units.

Q. What impact did these EPA regulations have on the Company's retirement decision for its Crystal River South coal plants?

A. Initially, the Company faced the retirement of CR1 and CR2 as early as 2015, with a possible extension to 2016. This extension was granted by the FDEP earlier this year, based on the time DEF needed to complete modest upgrades to the CR1 and CR2 units under a plan the Company developed for limited continued operation of CR1 and CR2 in compliance with MATS. The FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant Florida electric grid reliability issues identified by the FRCC in its MATS study completed in 2013.

The FRCC MATS Study evaluated the impact of a MATS-required shutdown of CR1 and CR2 on the reliability of the Florida Bulk Electric System ("BES"). The FRCC is responsible for ensuring that the Florida BES is reliable and adequate. The FRCC concluded, based on its analysis in 2013, that shutting down CR1 and CR2 in 2015 as a result of MATS would result in significant, adverse transmission impacts to the BES. The FRCC found that, at a minimum, the one-year extension of the MATS compliance deadline was needed to provide time to alleviate the significant transmission reliability issues that the FRCC identified in the MATS Study. The FDEP considered the FRCC conclusions in its

decision to grant the one-year extension to 2016 for CR1 and CR2 to comply with MATS. A copy of the FRCC MATS Study is attached as Exhibit No. ___ (BMHB-1) to my direct testimony.

During 2013, the Company further evaluated the continued operation of Crystal River South in compliance with MATS and other environmental regulations and determined that the Company could continue to operate CR1 and CR2 beyond 2016 with certain modifications to the units and a change to lower sulfur coal blends burned at the plants. The Company evaluated this plan against other options, concluded that the plan was the most cost-effective option, and presented this plan to the Commission in December 2013 as a modification to its Integrated Clean Air Compliance Plan. More detail on the Company's compliance strategy for CR1 and CR2 in response to MATS and other environmental regulations is provided in the Company's petition to modify its Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI. The Commission approved this modification to its Integrated Clean Air Compliance Plan in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014).

The Company now plans to continue commercial operation of CR1 and CR2 until 2018 in compliance with the Commission-approved modification to its Integrated Clean Air Compliance Plan. This decision reduces the generation capacity the Company needs prior to 2018, but the Company still needs generation capacity to reliably serve its customers commencing in this time period.

Q. What were the Company's other generation retirement decisions?

A. The Company projected the retirement of some of its oldest combustion turbines in its fleet in 2014 and 2016. These projected retirements were identified in the Company's resource planning process in the late 2000's and continued to be part of the Company's resource plans in its 2013 and 2014 TYSPs. These combustion turbines were installed in the late 1960's and early 1970's at Avon Park, Turner, and Rio Pinar. They collectively provide 133 MW of summer generation capacity to DEF's system. They are smaller, less efficient combustion turbines and they are increasingly more costly to operate and maintain. The Company will retire all of these combustion turbine units by 2016.

The Company also plans to retire its three 1950's vintage oil- and gas-fired steam generation plants at the Company's Suwannee power plant site by 2016. These are small units, collectively providing 128 MW of summer capacity to DEF's system. These units were slated for retirement in 2018 as they approach the end of their life cycle. DEF will retire these units in 2016 to reduce the cost of the transmission upgrades needed for installation of the proposed peakers.

These generation plant retirements contribute to the Company's generation capacity needs prior to 2018. Coupled with load growth identified in the Company's 2013 and 2014 TYSPs, the Company needs additional generation capacity prior to 2018 to reliably serve customers.

Q. What did the Company do in response to this identified need in 2016?

A. The Company evaluated several alternative generation options to meet this need including (i) construction of new generation; (ii) purchases from or acquisitions of existing generation plants owned by other companies; and (iii) power uprate projects at existing generation plants on the Company's system. The Company identified a need up to 1,150 MegaWatts ("MW") of additional generation capacity beginning in 2016 and established a process for Commission review of the Company's evaluation of this need in its Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement"). In the 2013 Settlement, the Company agreed to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 through its Integrated Resource Planning ("IRP") methodology and to present this evaluation to the Commission.

Q. Does the Company still need up to 1,150MW of generation commencing in 2016?

A. No. As I explained above, the Company's decision to complete projects necessary to permit the continued operation of CR1 and CR2 with alternative, low sulfur coal fuel sources and site averaging to comply with MATS extends the operation of CR1 and CR2 to 2018. This decision reduces the Company's generation capacity needs commencing in 2016. As a result, the Company no longer needs up to 1,150 MW of generation capacity commencing in 2016. The Company's need now is approximately 280 MW of summer generation capacity commencing in 2016 that increases to 470 MW in the summer of 2017.

Q. What is the Company's plan to meet its generation needs commencing in 2016?

A. The most cost-effective resource plan to meet the Company's summer generation capacity needs commencing in 2016 includes the construction of a new 320 MW simple cycle combustion turbine plant consisting of two F class combustion turbine units at the Company's Suwannee power plant site. This is called the Suwannee Simple Cycle Project. This plan also includes the installation of a 220 MW chillers power uprate project for the Company's existing natural gas-fired, combined cycle power blocks at the Company's Hines Energy Complex ("HEC"). This is called the Hines Chillers Power Uprate Project. This is the most cost-effective generation resource plan available to the Company for its customers to meet the Company's near-term generation needs commencing in 2016 based on both price and non-price attributes.

Q. Is the Company's decision with respect to its generation needs prior to 2018 consistent with the 2013 Settlement Agreement?

A. Yes. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the types of generation options specifically contemplated in the 2013 Settlement Agreement to meet the Company's generation capacity needs prior to 2018. The Company's decision to select these projects to meet its reliability need is the result of the IRP methodology that the Company agreed in the 2013 Settlement Agreement to use to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 and

present to the Commission for approval. Indeed, the parties to the 2013 Settlement Agreement agreed that DEF could seek Commission approval for the costs of additional generation to meet a need up to 1,150 MW in the 2013 Settlement Agreement, however as I explained above, the Company's ability to cost-effectively comply with MATS and extend the commercial operation of Crystal River South has reduced the Company's estimated need prior to 2018 from up to 1,150 MW to approximately 500 MW. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost-effective generation options to meet that need.

DEF has met with the parties to the 2013 Settlement Agreement several times to explain DEF's approach to its generation needs prior to 2018 and, ultimately, DEF's analyses and decision to meet that need consistent with the terms of the 2013 Settlement Agreement. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain the Company's Resource Planning Process.

A. The IRP process is an integrated process in which the Company seeks to optimize its supply-side and demand-side options into an integrated optimal plan designed to deliver reliable, cost-effective power to DEF's customers. On an annual basis, and when circumstances materially affecting the Company's current resource plan change, we evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed. Based on that evaluation, we develop the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This Integrated Optimal Plan is typically presented to the Commission in April each year in the Company's annual TYSP filing. The Company's current 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What reliability standards does the Company use to determine the need for additional resources?

A. DEF plans its resources in a manner consistent with utility industry resource planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF has used dual reliability criteria since the early 1990s in its IRP process and this practice has been accepted by the Commission. DEF uses both the Reserve Margin and LOLP planning criteria to ensure that its resource plan has sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions in the Company's service territory.

Q. Why are reserves needed?

A. Utilities require reserves to provide a margin of generating capacity above the firm demands of their customers in order to provide reliable electric service.

Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. Also, at any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis. For all these reasons, DEF plans generating capacity reserves into its optimal resource plan.

Q. What is DEF's Reserve Margin in its Integrated Resource Plan?

A. DEF's current minimum Reserve Margin threshold is 20 percent. The Reserve Margin is a deterministic measure of reliability. Reserve margin is the amount of capacity that a utility maintains above the peak forecast load expressed as a percentage of the load. The Commission approved this minimum Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Commission Order No. PSC -99-2507-S-EU.

Q. What is LOLP and what does it measure?

A. The LOLP is a probabilistic criterion that measures the probability that a utility company will be unable to meet its load throughout the year. Where Reserve Margin considers only the peak load and amount of installed resources, LOLP also takes into account a utility's load shape, generating unit sizes, capacity mix,

maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard LOLP probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability. In most cases, however, the need for additional generation capacity is triggered by the 20 percent Reserve Margin requirement before the LOLP criterion is considered. DEF's need for additional generation capacity prior to 2018 is also based on DEF's 20 percent Reserve Margin requirement.

Q. How did you start your resource plan that led to the identification of your need beginning in 2016 based on your reliability criteria?

A. As I explained above, there were certain retirement decisions, in particular, the retirement of the Company's CR3 nuclear plant, and the planned retirement of the Company's Crystal River South coal plants around changing environmental requirements, that drove the Company's near-term reliability needs as the Company entered 2013. The generation capacity need resulting from these decisions was coupled with additional load growth as a result of the Company's routine update of its forecast of system load growth for the next ten years as part of the normal IRP process. The Company's load forecast draws on the collection of certain input data, such as population growth, fuel prices, and interest and inflation rates. The load forecast is then developed based on economic and demographic assumptions that impact future energy sales and customer demand. The Company's load forecast is another key driver of the Company's resource

plan in the IRP process. The Company's load forecast methodology is described in detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Can you generally describe DEF's system demand and energy forecasts?

A. Yes. The Company's summer firm demand is expected to grow to 9,149 MW by the summer of 2016, which represents approximately a 3.8 percent growth rate from 2014. The net energy for load is projected to grow to 41,098 GWh in 2016, which represents approximately a 3.3 percent growth rate from 2014. The demand and energy forecasts are discussed in more detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What is the impact of the Company's load forecast on the Company's generation resource needs?

A. The Company will experience load growth as the Florida economy recovers from the last recession. DEF expects both more customers and growth in energy demand in the near term, through 2017, albeit at a slower pace than customer and energy demand growth before the recession. This is a change from the loss of customers and reduced demand at the height of the recession in 2009. The Company has slowly recaptured the ground lost during the recession and expects continued growth in customers and demand. This growth, especially in summer peak demand on the Company's system, is one driver of the need for additional

generation. Additionally, as I explained above, the need for additional generation is driven by the Company's decisions to retire generation capacity on its system. Together, the Company's projected capacity needs resulting from the Company's projected load growth, and existing and planned retirements, among other factors, demonstrate a need for additional capacity of approximately 280 MW in the summer of 2016 increasing to a need for 470 MW by the summer of 2017. Exhibit No. ____ (BMHB-3) is a summary of the Company's summer load forecast during this period.

Q. What is the impact on the Company's Reserve Margin?

A. DEF needs additional generation in the summer of 2016 and 2017 to meet its 20 percent minimum Reserve Margin requirement. Exhibit No. ___ (BMHB-4) shows DEF's forecast of summer peak demand and reserves, with and without any summer capacity additions. For the period from the summer of 2015 to the summer of 2017, DEF projects that the growth in firm summer peak demand will average approximately 132 MW a year with a projected peak in 2016 of 9,149 MW and in 2017 of 9,307 MW. The exhibit also shows that DEF will have a total generating capability of approximately 11,012 MW by the summer of 2016 and 11,232 MW by the summer of 2017. This capacity includes the installation of the Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017.

As demonstrated in this exhibit, without these capacity additions, DEF's Reserve Margin will decrease to 16.9 percent in the summer of 2016 and 14.9

percent by the summer of 2017. DEF maintains its Reserve Margin for its summer (and winter) peak demands to ensure reliable electric service to its customers. DEF needs additional generation capacity in the summer of 2016 and the summer of 2017 to meet its obligation to provide reliable electric service to its customers.

Q. Did the Company consider non-generating alternatives to meet the Company's capacity need commencing in 2016?

A. Yes, energy conservation and direct load control programs are always a part of the Company's IRP process and they were considered in connection with the Company's near-term generation capacity need commencing in 2016. The Company's current demand-side management ("DSM") programs were included in the Company's Base Generation Expansion Plan that contains the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate project. As evidenced by the inclusion of these projects in the Company's Base Generation Expansion Plan, however, The Company's current DSM programs cannot replace or defer the Company's need for additional generation on its system to meet the Company's generation capacity needs commencing in 2016.

Q. What are the Company's current DSM programs?

A. DEF's current DSM programs were essentially set forth in the DSM Plan approved by the Commission in Order No. PSC-11-0347-PAA-EG in August 2011. In this Order, the Commission modified the Company's DSM Plan,

effectively approving the Company's DSM programs that were in effect in August 2011. In 2012, additional revisions to four Company DSM programs resulting from changes in the Florida Building Code were approved, otherwise the Company's current DSM programs are the same as the programs the Commission approved in Order No. PSC-11-0347-PAA-EG. With these revisions, DEF's Commission-approved DSM Plan consists of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs. These DSM programs will continue to be offered to the Company's customers through 2014 as the Company's current DSM Plan extends through the end of the year. A more detailed description of the Company's DSM programs is contained in the Company's 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Did the Company's continuing IRP planning process in 2014 reveal new or revised DSM programs or measures that satisfied or deferred the Company's generation capacity needs commencing in 2016?

A. No. DEF performed the DSM evaluations necessary for the Commission's current DSM goals docket that will set DEF's future DSM goals for the period 2015 to 2024. Based on the results of that evaluation, there are no additional DSM measures or programs that can replace or defer the Company's need for additional generation capacity prior to 2018 to reliably serve DEF's customers. There is no reason to conclude, then, that the Company's determination that it

needs additional supply-side generation capacity commencing in 2016 will be affected by the outcome of the current DSM goals docket.

Over the next ten years the Company's proposed conservation goals are generally lower than the existing DSM goals. All other things being equal, then, the Company's near-term DSM goals cause an increase in DEF's firm summer peak demand in 2016 and 2017, and, therefore, further establish the need for the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's reliability needs in 2016 and 2017.

DEF's proposed DSM Plan reflects the successful implementation of cost-effective DSM programs by the Company for the past thirty years to reduce energy demand and energy consumption and therefore avoid the need for new generation. Through 2011, DEF's Commission-approved DSM programs have achieved more than 5,000 GWh reductions in energy consumption and over 1,645 MW in demand savings, effectively eliminating the need for the Company to build and operate approximately eighteen (18) new peaking power plants. The elimination of the need to build additional generation plants has resulted in over $1.2 billion in customer energy savings.

Substantial reductions in energy consumption and demand already have been achieved by the Company in its service territory, necessarily resulting in diminishing future energy consumption and demand reductions from future energy efficiency programs and measures. It is simply more difficult to achieve additional reductions in energy consumption and demand, and more costly to do so too, with continued or new DSM programs. More simply put, DEF's past

success with its DSM programs makes it more difficult to get more "bang for the buck" with new or revised DSM programs.

In addition, DEF's new DSM programs are competing with increasing gains in energy efficiency by measures implemented by customers themselves, either independently or as a result of other, non-utility incentives, such as building code changes for new customer construction. The Commission recognized this impact in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining to the Florida Legislature that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs. These impacts also make it more difficult and more costly to achieve each incremental increase in energy efficiency or demand reduction through DEF's DSM programs.

For all these reasons, as more fully explained by the Company in Docket No. 130200-EI, DEF's proposed DSM goals for the next ten years are lower than the Company's current DSM goals. As a result, the Company's proposed DSM goals have no impact on the Company's reliability need in 2016 and 2017. There simply are no cost-effective DSM measures or programs that can offset or defer the need for additional generation capacity beginning in 2016.

Q. Would the Company's reliability need in 2016 and 2017 be impacted if the results of the current DSM goals docket are different from what the Company expects them to be?

A. No. The Company firmly believes that its proposed DSM goals in Docket No.

130200-EI are reasonable, cost-effective goals for the Company and its customers, and that they will be accepted by the Commission. Even if the Commission for some reason departed from these proposed DSM goals, however, for several reasons the resulting goals would have no impact on the Company's reliability need in 2016 and 2017.

First, the future DSM goals will not even be established by Commission Order until the fall of 2014, at the earliest. The Company will then need time to evaluate, develop, and implement new or revise existing DSM programs and measures in an attempt to meet the new DSM goals. After these new or revised DSM programs and measures are implemented, there naturally will be a period of time before any results are observed in the Company's load and peak demand. The Company cannot obtain the new DSM goals, evaluate them, develop and implement new or revised DSM programs or measures to achieve those goals, and see the full results of these new or revised DSM programs or measures by the summers of 2016 and 2017 when the Company has a reliability need for new generation. Accordingly, even if the current DSM goals docket results in different, higher DSM goals for DEF than DEF has proposed in that docket, those DSM goals would have no impact on DEF's reliability need for additional generation capacity in the summer of 2016 and 2017.

Q. Are there other considerations in balancing demand- and supply-side resources?

A. Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. While dispatchable demand-side resources provide important and cost-effective resources to reduce load, they cannot be used as often or as long as physical generation without eventually affecting customer participation levels. Prolonged use of dispatchable DSM resources to meet customer load demand, especially in the summer months, will result in customer attrition in the dispatchable DSM program. Based on the Company's experience, when interruptions in customer service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, DEF carefully evaluates increasing reliance on dispatchable DSM programs to meet load with additional physical reserves to meet that load. In the case of the Company's additional capacity needs in the summers of 2016 and 2017, based on projected load growth and the Company's existing and planned generation retirements, the planned addition of generation projects will increase the Company's share of physical reserves to approximately 54 percent of total reserve capacity (which includes DSM) in the summer of 2017. See Exhibit No. ___ (BMHB-5) to my direct testimony. This level of physical reserves, in the Company's view, is, at a minimum, necessary to maintain coverage of an unplanned outage of the fleet's largest unit or to maintain coverage in an extreme weather event.

Q. Were supply-side alternatives identified and considered to meet the Company's capacity needs commencing in 2016?

A. Yes, in fact, the Company's optimization of its resource plan to meet its capacity needs commencing in 2016 in its IRP process determined that supply-side generation alternatives were necessary to cost-effectively meet customer capacity needs beginning in this time period. DEF examined several alternative generation expansion plans to meet this need, however, the alternative generation expansion plans that could be evaluated were limited by the need to place generation in-service in 2016 and 2017. With this limitation in mind, the Company evaluated generation options to determine those options that were the most cost-effective, screening the options based on cost, fuel sources and availability, technological maturity, and overall resource feasibility within the Company's system.

Generation alternatives that passed this screen were included in the Company's economic evaluation in the EPM production cost computer model. The primary output of EPM is a Cumulative Present Value Revenue Requirements ("CPVRR") comparison of the generation resource options that satisfied DEF's reliability requirements. The most cost-effective supply-side resources were evaluated and ranked by system revenue requirements. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project had the lowest CPVRR and were chosen by the Company as its Base Generation Plan to meet the Company's reliability needs in 2016 and 2017.

Q. Did the Company consider supply resources from other generation suppliers in its planning process to meet its capacity needs commencing in 2016?

A. Yes. DEF always takes into account the potential future supply of firm capacity from purchased power contracts during the study period in its evaluation. In fact, DEF determined that a short-term power purchase agreement ("PPA") with Southern Company over the limited transmission import interface was cost effective and included this purchase in its Base Generation Plan to meet its generation capacity needs commencing in 2016. DEF also evaluated several, other PPAs, and even acquisitions of generation facilities, to determine if they were more cost effective, considering all price and non-price attributes, than the Company's self-build new generation Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to meet the Company's capacity needs commencing in 2016. These other, potential generation alternatives, and the Company's evaluation of them, are discussed in more detail later in my direct testimony.

Q. Did the Company consider renewable energy sources and technologies to meet its capacity needs in 2016?

A. Yes. The Company evaluates the timelines for new technologies including renewable energy source and technologies on a continuing basis as part of its IRP process. The Company also has a Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects. The Company will continue to evaluate the development or purchase of renewable energy in the

future to potentially reduce DEF's use of fossil fuels or to defer or eliminate the need to construct more conventional, fossil-fueled generation resources.

Q. Were renewable energy sources or technologies reasonably available to the Company to meet its capacity needs commencing in 2016?

A. No. No commercially available, economically feasible renewable generation resource currently exists to displace or defer DEF's generation capacity needs commencing in the summer of 2016. DEF has a contract with U.S. Ecogen for a 60 MW plant that will use an energy crop as a fuel source with a planned in-service date of January 2017, however, that in-service date is uncertain and, even if this plant achieves commercial operation in January 2017, it does not address DEF's generation capacity need commencing in the summer of 2016, and it does not defer the need for generation capacity in the summer of 2017. Additionally, no other proposal for renewable energy projects have been received in response to the Company's RFR that will displace or defer the Company's generation capacity needs in 2016 and 2017.

V. THE SUWANNEE SIMPLE CYCLE AND HINES CHILLERS POWER UPRATE PROJECTS.

Q. Please explain the Company's plan to meet its capacity needs commencing in 2016.

A. The Company's plan includes the Suwannee Simple Cycle Project in the summer of 2016 and the Hines Chillers Power Uprate Project by the summer of 2017. As

I mentioned above, the Company also executed a short term PPA with the Southern Company for generation capacity commencing in 2016 as part of its base generation plan with the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. Both Company projects are necessary to meet the Company's summer Reserve Margin requirement in 2016 and 2017 to deliver reliable electric service to the Company's customers.

The Suwannee Simple Cycle Project consists of two F class combustion turbine generators, two generator step-up transformers, fuel oil and demineralized water storage tanks, and related balance of plant facilities installed by June 2016 at the Company's existing Suwannee power plant site in Suwannee County, Florida. The Suwannee power plant site has existing infrastructure to support the Suwannee Simple Cycle Project. The Suwannee plant site has existing gas- and oil-fired combustion turbines, steam units and a transmission switchyard among other facilities. The new F class combustion turbine generators will be connected via a gas lateral to the Florida Gas Transmission gas pipeline and to the existing site metering and regulating station. One combustion turbine will be connected to the existing 115 kv transmission switchyard and the other combustion turbine will be connected to the existing 230 kv transmission switchyard. This existing infrastructure at the Suwannee site reduces the cost of the Suwannee Simple Cycle project. The estimated cost of the Suwannee Simple Cycle project, including the Allowance for Funds Used during Construction ("AFUDC"), is $197 million. The Suwannee Simple Cycle Project is explained in more detail in the testimony of Mr. Landseidel in this proceeding.

The Hines Chillers Power Uprate Project involves the installation of a chiller system designed to cool gas turbine inlet air to 50 degrees F and, therefore, increase the summer capacity of the combustion turbines for all four existing power blocks at the HEC. The HEC contains four natural gas-fired combined cycle units or power blocks with approximately 1,900 MW of total installed capacity. The Hines Chillers Power Uprate Project is projected to increase the total HEC power block summer output by approximately 220 MW. The Hines Chillers Power Uprate Project involves the installation of chiller modules and a large chilled water storage tank, auxiliary power system, pumps and chilled water supply and return piping, and gas turbine air inlet chiller coils including modification of the air inlet ducts on the existing power blocks. The estimated cost of the Hines Chillers Power Uprate Project, including AFUDC, is $160 million. The Hines Chillers Power Uprate Project is also explained in more detail in Mr. Landseidel's testimony in this proceeding.

Q. What impact will the addition of the Suwannee Simple Cycle and Hines Chillers Power Uprate projects have upon DEF's Reserve Margin and its ability to provide reliable service to its customers?

A. As shown in Exhibit No. ___ (BMHB-4), the addition of the Suwannee Simple Cycle Project will increase DEF's summer peak Reserve Margin to 20.4 percent in the summer of 2016. The addition of the Hines Chillers Power Uprate Project by the following summer will increase DEF's 2017 summer peak Reserve Margin to 20.7 percent. See Exhibit No. ___ (BMHB-4). The Suwannee Simple Cycle

and Hines Chillers Power Uprate Projects allow DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin.

Q. Why did DEF select the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects as the Company's generation options to meet its need in the summers of 2016 and 2017?

A. DEF's resource planning analyses show that the economics favor these projects over other Company generation options that were available to meet its near-term capacity needs in the summers of 2016 and 2017. The Company evaluated new generation, existing plant uprate projects, and existing generation life extension projects to meet this need. This evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options. Based on this evaluation, the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects were the most cost-effective generation options, based on price and non-price attributes, to meet the Company's reliability needs in the summers of 2016 and 2017. Exhibit No. ___ (BMHB-6) to my direct testimony shows the range of projects considered. I will note that at this point in the Company's evaluation, the Hines Chillers Power Uprate Project was considering chilling systems on only 3 of the 4 HEC power blocks (Power Blocks 2, 3, and 4). Further evaluation on Power Block 1 was centered around the thermal performance uprate ("TPU"). The TPU was not deemed to be economically favorable and was later dropped for consideration.

Q. What are the transmission impacts and benefits of the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects?

A. There are no additional transmission costs associated with transmission enhancements or modifications for the Hines Chillers Power Uprate Project. These are power uprates to the existing HEC power blocks which are supported by the existing transmission system connecting the HEC to DEF's system. There are limited transmission system network upgrades and costs for the Suwannee Simple Cycle Project associated with the transmission interconnection of the combustion turbines at the existing Suwannee site. These are added customer benefits from installing these projects at existing power plant sites on the Company's system compared to generation at a Greenfield site. These transmission costs and benefits are also explained in the direct testimony of Mr. Ed Scott in this proceeding.

Q. Are there environmental benefits associated with the Suwannee Simple Cycle and Hines Chillers Power Uprate projects?

A. Yes. Both projects are located at existing brown field, power plant sites. Both projects have limited to no additional environmental impact at the existing sites. As a result, the Company is able to add over 500 MW of additional summer generation capacity by the summer of 2017 with little to no additional environmental impact. These projects provide the Company with the ability to substantially increase its summer generation capacity to meet customer energy

demand while maintaining the Company's compliance with current and future environmental regulations.

VI. DEF'S GENERATION RESOURCE OPTIONS ASSESSMENT .

Q. Did DEF evaluate other supply-side alternatives to meet its generation needs in the summers of 2016 and 2017?

A. Yes. The Company evaluated PPAs from other utilities and non-utility generators and the acquisition of existing, non-utility generation plants in addition to the Company's self-build generation options. These are the same options that the Company said it was going to evaluate in the 2013 Settlement Agreement approved by the Commission.

Q. Please describe DEF's efforts to solicit proposals from other supply-side providers to meet its capacity needs commencing in the summer of 2016.

A. DEF first contacted other utilities and non-utility generators with the capability of supplying some or all of the Company's near-term capacity needs in September 2012. DEF issued a solicitation for proposals for PPAs. Bids were initially received in October 2012, evaluated in November 2012, and a short list was identified and negotiations over draft PPAs commenced in January and February 2013. Changes with the Company's resource plan, in particular with the decision to retire CR3 and the potential early retirement of CR1 and CR2 in this same time period, required the Company to re-evaluate its resource plan and its generation capacity needs. This re-evaluation led the Company to identify a potential near-

term generation capacity need of up to 1,150 MW in the 2013 Settlement Agreement. At the same time, however, the Company was evaluating a plan to continue commercial operation of Crystal River South in compliance with MATS through site averaging for another two years. As I explained above, the Company ultimately determined that it could operate Crystal River South until 2018 under a MATS compliance plan and it has implemented that plan with Commission approval. The implementation of this plan to continue the operation of Crystal River South to 2018 substantially reduced the Company's summer generation capacity needs prior to 2018.

DEF requested renewed proposals for PPAs and solicited interest in potential generation facility acquisitions from the potential generation suppliers who responded to the Company's earlier RFP. These potential suppliers submitted renewed bids for PPAs and generation facility acquisition offers to meet DEF's near-term generation capacity needs in September and October 2013. The Company evaluated these proposals and followed up with the bidders regarding additional information, issues, and potential supplemental offers from October 2013 through February 2014.

Q. Please explain the supply-side proposals you received.

A. The Company invited alternative proposals that offered superior customer value to the Company's self-build generation options to meet the Company's near-term capacity needs prior to 2018. We sought reliable, dispatchable, and financially sound proposals that would provide the Company generation capacity by the

summer of 2016 and/or the summer of 2017. We received nine proposals for PPAs or generation facility acquisitions from seven participants. We evaluated all of these proposals by systematically following a structured, orderly evaluation process that evaluated all proposals, including the Company's self-build generation projects, on price and non-price attributes.

After initial screening, DEF evaluated both generation facility acquisition and PPA proposals from two participants. There was one system PPA proposal from another investor-owned utility, two PPA proposals from non-utility generators and three additional generation facility acquisition proposals. A confidential chart of these supply-side generation proposals that were received and evaluated by the Company to meet its capacity needs commencing in the summer of 2016 is included in Exhibit No. ___ (BMHB-7) to my direct testimony.

Q. Please describe the evaluation process.

A. The evaluation process involved an analysis of the price and non-price attributes on all the supply-side generation proposals received and the Company's self-build generation options. The proposals were first segregated into categories distinguished by the type of proposal and term to ensure a consistent and fair evaluation by categorizing and evaluating "like type" proposals. Next, the Company conducted an economic evaluation of the proposals. In this step, the proposals were screened based on the fixed and variable payments or costs and economic optimization screening analyses were performed.

The Company also preliminarily evaluated the technical feasibility and viability of the proposed acquisitions through an analysis of such factors as the operating, maintenance, and physical conditions of the plants. Other non-price attributes, including insurance, project risk, environmental impacts and compliance, and regulatory feasibility, among other factors, were also considered. This preliminary qualitative assessment was undertaken to determine if there were any proposals that were such outliers from a qualitative risk perspective that further economic evaluation was unnecessary. Upon the completion of the economic evaluation, however, a more detailed qualitative evaluation was necessary, assuming that one or more proposals were economic, before the Company could conclude that a proposal was the most cost effective generation capacity option for DEF's customers.

Finally, the Company conducted a detailed economic evaluation of each proposal compared to DEF's self-build generation alternatives, the Suwannee Simple Cycle and the Hines Chillers Power Uprates projects. This detailed economic evaluation included all costs, including transmission cost impacts, in the analysis.

Q. How did the Company perform the detailed economic evaluation?

A. The Company performed a detailed economic optimization analysis of the alternative and Company supply-side generation proposals to meet its capacity needs beginning in the summer of 2016. The purpose of the optimization analysis was to develop an optimal resource plan for each proposal for the detailed

economic analysis. The optimization analyses were performed for a period of thirty years to capture all costs associated with each proposal and, in particular, to determine the type of units that make up the optimal resource plan including a proposal.

The optimization analysis was performed using the Strategist optimization model. While the economic screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of the Company's base case self-build generation plan. The optimization analysis, therefore, shows the net impact of both the proposal cost and the impact the proposal has on system capital revenue requirements and fixed and operating costs. Such an analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs. DEF integrates the resource plan optimization and fixed cost results including capital revenue requirements for generation and transmission from Strategist with the detailed production cost results from the EPM model in its detailed economic evaluations.

Q. What was the Company's base case generation plan in its detailed economic evaluation?

A. The base case was the Suwannee Simple Cycle and Hines Chillers Power Uprate projects in the summers of 2016, and 2017, respectively, followed by the other planned generation units included in the Company's 2014 TYSP. The base case

or "self-build" option included chillers at only three Hines power blocks at this stage of the analysis. See Exhibit No. ___ (BMHB-2).

Q. Please explain what the Strategist optimization model is and what it does.

A. The Strategist optimization model is an industry-recognized utility system production cost model that we use to develop optimal resource plans. Strategist is a detailed, chronological production costing model that simulates each generating resource on the DEF system, both existing and future, and how each resource is used to serve the forecasted peak demand and energy requirements of DEF's customers. The objective function of the Strategist model is to minimize the cumulative present value of revenue requirements ("CPVRR") for the DEF generation system, subject to the 20 percent Reserve Margin constraint.

Thus, for each resource proposal evaluated, the Strategist model provides the optimal generation expansion plan for the 30-year study period, if the proposed resource was selected. Inputs to the model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the Company's existing generating units and purchase power agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are also included in the model. Strategist model runs develop alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative from lowest to highest cost. From an

economics-only perspective, the lowest cost plan is the optimal plan.

Q. How were the results of the Strategist model optimization analysis used?

A. The results of the Strategist optimization cost analyses were used to identify optimal resource plans corresponding to each of the proposals or self-build options selected for evaluation. DEF reviewed the best plans produced by Strategist for each option and selected the plan with the lowest CPVRR for each that was feasible given constraints of transmission, construction, permitting, and other factors. The fixed cost output from Strategist was then incorporated into the financial analysis of each alternative proposal.

Q. How were the production costs associated with each alternative proposal determined?

A. After using Strategist to identify the lowest cost plan candidates, DEF uses the Planning and Risk module of the Energy Portfolio Manager ("EPM") software to further evaluate the production cost results. EPM is a detailed production cost model which evaluates the fleet dispatch in each hour over the period of the study taking into consideration both costs and projected operating constraints such as unit start times, minimum up and down times, reliability must run requirements, and projections of planned and unplanned outages. The analysis must capture these costs because each alternative proposal, due to, for example, its size, heat rate (if relevant), proposed pricing, and other factors, causes the other resources on the DEF generation system to operate in a different manner, resulting in

different total system production costs. Production cost results from EPM were combined with fixed cost calculations from Strategist to calculate total 30-year production costs for each proposal and a resulting CPVRR for each proposal alternative. The cost results and CPVRR for each proposal is reviewed individually and then compared to the self build case.

Q. Were any other cost impacts included in the analysis?

A. Yes. The fixed costs of the alternatives, that is, the fixed charges of the proposals and the construction costs and fixed O&M costs of the Company's self-build generation projects, were captured in the financial analysis. The transmission construction costs to integrate each of the proposals and the Company's self-build generation projects into the transmission system were also included in the detailed economic analysis. The annual cash flow pattern of these transmission construction costs was based on typical expenditure patterns. All these costs were captured in the Strategist modeling analysis. Finally, we also evaluated the cost of imputed debt by determining the additional equity cost related to the purchased power proposals. The cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. The cost of imputed debt is a real cost associated with a PPA proposal and it therefore needs to be considered by the utility in determining the most cost-effective resource to meet its customers' reliability needs. In this case, because the term of the PPAs

evaluated was five years or less, the impact of the imputed debt was found to be less than $5 million and was deemed to be not material in the results.

Q. What were the results of the detailed economic analysis?

A. In CPVRR terms, the Company's base generation plan --- the Suwannee Simple Cycle and Hines Chillers Power Uprate projects --- was found to be less expensive or more cost effective than all of the PPA proposals and all but one of the potential generation facility acquisition proposals. The Company's base generation plan was only marginally more expensive than one of the acquisition proposals, but in CPVRR terms over the 30-year study period they were nearly equivalent on an economic basis to the Company. Another potential generation facility acquisition proposal ranked third behind this generation facility acquisition and the Company's base generation plan by almost $200 million. Exhibit No. ___ (BMHB-8) to my direct testimony show the results of the initial detailed economic analysis.

Q. Did DEF consider combining one of the self-build projects with the alternative proposals?

A. Yes. DEF tested the proposals with and without the Hines Chillers. Initially, this was because some of the proposals (e.g. Acquisitions 4 and 5) did not supply sufficient MWs to meet DEF's need. During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Chillers. In each case, addition of the Hines Chillers made the project more favorable from a

CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. As a result, all of the resource plans represented in Exhibit No. __ (BMBH-8) include inlet chilling on three Hines Power Blocks.

Q. What was DEF's next step in the analysis?

A. Following review of the initial detailed economic results, DEF quantified a number of sensitivity risks around the proposals evaluated. Included in these risks were construction cost sensitivity around the Suwannee and Hines projects, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks. Exhibit No. ___ (BMHB-9) shows the results of the cost risk sensitivity analysis.

Given the range of values, DEF looked closely at two acquisition proposals as alternatives to the DEF self-build project. These were Acquisitions 1 and 2. In the case of Acquisition 1, while the option had an apparently positive CPVRR relative to the self-build option, DEF recognized that there were a number of costs that might not be fully developed. Chief among these undeveloped costs was the fact that the option had been evaluated based on its existing fuel purchase arrangements. DEF recognized that these existing arrangements provided less firm gas transportation than would be typical for a DEF facility of this type. While this might be suitable for an Independent Power Producer like Acquisition 1, further evaluation would be warranted to determine if this would provide adequate reliability for a utility asset.

In the case of Acquisition 2, DEF had made conservative assumptions

regarding the cost of transmission upgrades required to deliver the power from Acquisition 2 to DEF. DEF recognized that further analysis might yield a lower cost solution. For this reason, DEF looked more closely at Acquisition 2. However, in all the acquisition cases, DEF recognized the risk that due diligence might identify differences in maintenance practices, spares stocking, or issues around unit condition, among other factors, that would add cost to these acquisition alternatives. Based on the results of these initial economic analyses, DEF concluded that there was potential for two of the acquisitions to be competitive to the self-build and that it would be prudent to proceed with an evaluation of the FERC market screen risks associated with the two acquisitions before concluding the economic analysis and proceeding to the due diligence evaluation of the potential acquisition options.

Q. What additional analyses with respect to these proposals did DEF perform?

A. Because the cost sensitivities showed that two generation facility acquisition proposals had the possibility of being close in the CPVRR analyses to the Company's base generation plan the Company took the next step in determining the feasibility of any proposed generation facility acquisition by conducting a Federal Energy Regulatory Commission ("FERC") market screen analysis.

The FERC market screen analysis is a required step in obtaining FERC approval under section 203 of the Federal Power Act ("FPA") for any public utility acquisitions of jurisdictional generation facilities. Pursuant to FPA section 203, the FERC must determine that a public utility generation facility acquisition

transaction is in the public interest. To make this determination, FERC reviews the proposed transaction to assess its effect on competition in the wholesale market, wholesale rates, and regulation. The FERC market screen, or Competitive Analysis Screen, is part of this review under the Antitrust Agencies' Horizontal Merger Guidelines adopted by FERC. FERC must approve any potential generation facility acquisition by the Company before the Company can complete that acquisition.

Q. How did the Company assess the competitive impact of its proposed generation facility acquisition under the FERC market screen test?

A. The Company retained Julie Solomon with Navigant Consulting, Inc. to perform the FERC market screen analysis. Julie Solomon and Navigant are well-recognized industry experts in this area. Julie Solomon has performed the FERC market screen analysis dozens of times for potential mergers or generation facility acquisitions and she has filed testimony many times at FERC regarding the implementation and application of the FERC market screen to such transactions.

Q. What were the results of the FERC market screen analysis?

A. Both potential generation facility acquisitions that were evaluated failed the FERC Competitive Analysis Screen. Failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition transaction without mitigation efforts by the Company to eliminate the screen failures. The FERC market screen analysis and the results of that analysis

are explained in more detail in the direct testimony of Julie Solomon filed on the Company's behalf in this proceeding.

Q. What did the Company do with the FERC market screen analysis results?

A. The Company decided, based on these results, that the potential generation facility acquisitions were not cost effective for the Company's customers and should not be considered further by the Company. The Company determined that the Company's base generation plan was the most cost-effective resource plan to meet customer reliability needs in the summers of 2016 and 2017.

Q. Why did the Company make this decision?

A. Both potential generation facility acquisitions failed the FERC Competitive Analysis Screen. As explained by Julie Solomon in her testimony, failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition without structural mitigation to mitigate the screen failures. There are two potential FERC-approved mitigation measures. One is for the Company to sell its own generation facilities to reduce DEF's owned or controlled generation capacity in the market. This mitigation measure makes no sense for the Company. DEF cannot sell off generation because DEF needs additional generation capacity to provide reliable electric service to its customers. This remedy is not a reasonable mitigation measure for the Company.

Another FERC-approved mitigation measure is adding transmission import capability to reduce DEF's share of the generation capacity in the market

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

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

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

warrant hundreds of millions of dollars in transmission system facility upgrades that DEF and its customers must incur to mitigate the FERC screen failures for this potential acquisition. The other potential generation facility acquisition evaluated under the FERC market screen analysis was already almost $200 million less cost-effective on a CPVRR basis than the Company's self-build generation plan, largely due to transmission system upgrades already required to incorporate the generation facility into DEF's system. The additional transmission system facility upgrades to provide a minimum of 1,000 MW of additional transmission import capability to mitigate the FERC screen failures for this potential generation facility acquisition clearly render this acquisition uneconomic for DEF and its customers.

Q. Were there any other factors that led the Company to determine that pursuit of FERC approval for these potential generation facility acquisitions was not in the best interest of the Company's customers?

A. Yes. Apart from the quantitative factors that render the potential generation facility acquisitions uneconomic, they are also qualitatively not the most cost effective options for DEF and its customers. DEF must still seek FERC approval for the generation facility acquisitions even if DEF elected to pursue mitigation, which as I explained above, is not an economically viable option for the Company. At a minimum, this means the Company must incur the cost and spend the time necessary to retain experts and develop the analyses for the case for FERC approval, and then initiate the FERC proceeding to obtain that approval,

which is uncertain. The FERC proceeding, at a minimum, will take six months before the Company obtains a FERC decision. This is unacceptable to DEF and its customers. Setting aside the cost of the expert analyses and the FERC proceeding itself and the uncertainty of the outcome of that proceeding, DEF must make investment decisions now to ensure that it can reliably provide its customers with additional generation capacity in 2016.

Qualitatively too, there were other risks associated with these potential generation facility acquisitions that likely would have rendered them not cost-effective for DEF and its customers. DEF deployed a step-wise approach and evaluated these generation facility acquisitions first on the bases of CPVRR and FERC market screen analyses. Until DEF determined: (1) whether a potential acquisition was economically competitive; and (2) whether or not a potential acquisition could pass the FERC market screen, it did not make sense for DEF to complete its due diligence on these plant acquisitions, or engage in negotiations over the terms of the plant acquisitions. The condition of the plants; the environmental conditions of the plant sites; plant performance history, warranties and guarantees; financial guarantees; insurance and indemnity obligations, among other factors, would be fully evaluated only if the potential acquisition was shown to be economically competitive and capable of passing the FERC market screens. These additional qualitative factors, however, represent additional, unmitigated risk associated with the potential generation facility acquisitions that preclude the Company from determining that they are cost effective for customers.

As a result of the Company's economic and FERC market screen analyses

and its evaluation of the qualitative risks associated with the proposed generation facility acquisitions, the Company determined that further review of the generation facility acquisition proposals was unnecessary. The most cost effective generation option to meet customer reliability needs prior to 2018 is the Company's self-build generation plan.

Q. Did you perform additional economic analyses following the results of the FERC market screen?

A. Yes. DEF updated the results of the most favorable remaining alternatives, adjusting the modeling case to the latest assumptions consistent with the 2014 TYSP. While this did not have a significant effect on the results, the results are shown in Exhibit __ (BMBH-10). This exhibit shows the difference in total system CPVRR associated with each supply-side generation alternative proposal compared to the Company's Base Generation Plan. DEF evaluated the highest ranking of the PPA options from the previous review and the remaining PPA-acquisition hybrid that DEF believed would pass the market screen. Both of these were significantly less cost effective than the self-build option. Prior to this point, all analyses had been done assuming that the chillers would be added only to Power Blocks 2, 3, and 4 at HEC. During this period, DEF engineering had concluded that it would be feasible to extend the chiller project to Power Block 1. The results in Exhibit __ (BMHB-10) continue to use the Suwannee project along with the three inlet chillers as the base case, but also shows the evaluation of the project with four chillers, and a resource plan in which the chillers were omitted

and replaced by a third combustion turbine at Suwannee in addition to the comparison with the remaining PPA alternatives. These results support the conclusion that the most cost effective plan is the construction of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project at all four Hines power blocks.

Q. Did you perform any sensitivity analyses?

A. Yes. DEF performed sensitivity analyses of the final alternatives in our High Gas Price sensitivity case and with no CO_2 price. These cases are typically run to establish the robustness of a conclusion and to indicate how the results will vary based on variation in fuel and emission pricing, typically two of the most sensitive inputs to the production cost model. The results of these analyses are shown in Exhibit __ (BMHB-11). Comparison of the results follow generally expected patterns, favoring portfolios with higher proportions of combined cycle in the high gas case and the reverse in the no CO2 case. Since the alternatives are all gas fired, the variations between cases are relatively small. The results of these sensitivity analyses support the conclusion that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project together form the most cost effective selection for DEF's need in 2016, 2017, and beyond.

VII. THE MOST COST-EFFECTIVE GENERATION ALTERNATIVE.

Q. Is the Company's base generation plan the most cost-effective alternative for meeting the Company's reliability needs in the summers of 2016 and 2017?

A. Yes, it is. The Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Suwannee Simple Cycle and Hines Chillers Power Uprate projects as its base generation plan to meet its reliability needs by the summers of 2016 and 2017. Further, through the Company's evaluation of market proposals for alternative generation, the Company determined that the Suwannee Simple Cycle and Hines Chillers Power Uprate projects were more cost-effective, on a quantitative and qualitative basis, than any of alternative supply-side generation proposal on the market.

Q. What caused the Company's Base Generation Plan to be more cost effective than any of the other alternatives?

A. The Suwannee Simple Cycle Project is a new, state-of-the-art combustion turbine plant with higher fuel efficiency than existing combustion turbine PPAs or the acquisition of existing combustion generation facilities. As I explained above and as explained in more detail in the direct testimony of Mr. Landseidel, there are also economic benefits associated with its location at an existing Company power plant site. Further, there are no FERC market screen issues with new generation in the market. FERC is concerned with removing generation or the ability to remove generation from the market. For all these reasons, the Suwannee Simple Cycle Project proved to be a cost-effective part of the Company's base generation

plan to meet its reliability needs in 2016.

The Hines Chillers Power Uprate Project is the most cost-effective generation option in every generation alternative scenario. This project adds summer generation capacity with additional combined cycle power generation. As a result, the Company obtains additional summer peaking generation at combined cycle generation efficiency and cost. The fuel efficiency and relatively low cost of the Hines Chillers Power Uprate project make it a highly cost-effective generation option to meet DEF's customer reliability needs.

VIII. CONSEQUENCES OF DELAY

Q. What will be the impact of delaying implementation of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects?

A. If the Suwannee Simple Cycle and Hines Chillers Power Uprate projects are delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2016 and 2017, respectively, in the most reliable and cost-effective manner. This would expose DEF's customers to a risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. Even without an interruption in service, without the Suwannee Simple Cycle and Hines Chillers Power Uprate projects, DEF would be forced to enter into more costly PPAs to meet this near-term reliability need. As a result, DEF's customers would be subject to higher costs to serve their reliability needs in the summer of 2016 and 2017.

IX. CONCLUSION

Q. Please summarize the benefits of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects.

A. DEF needs the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building these projects the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Company has exhausted conservation measures reasonably available to the Company and there are no reasonably available renewable energy resources or technologies to meet the Company's near-term reliability needs in the summers of 206 and 2017. The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects are the most cost-effective resources to meet customer reliability needs in this time period. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

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)

Performed by the FRCC TWG

Prepared by TWG	**June 3, 2013**
Accepted by MSPC	**February 4, 2014**

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Summary

The FRCC TWG, under direction of the FRCC PC, has performed a study to determine the transmission reliability impact to the FRCC Region of the EPA MATS regulation. In order to comply with the MATS regulation, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). In addition to the potential impacts of the MATS regulation, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"). The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is a significant shift in power flow patterns causing reliability concerns in areas not previously identified.

The FRCC TWG finds the following with respect to the three MATS Study deliverables:

- An extension of at least one year on the EPA's MATS compliance deadline is needed for Crystal River 1 & 2. This will alleviate significant reliability issues that would begin in the summer 2015 timeframe (without such extension), ensuring BES reliability in the FRCC Region as various transmission projects and operational mitigation procedures are implemented.

- In 2016 and 2017, significant reliability issues continue to exist with the retirement/shutdown of the Crystal River units. The TWG requests that All entities with unresolved thermal and/or voltage criteria exceptions further investigate and develop mitigation plans.

- The results of the summer 2018 analysis for the potential addition of a combined cycle facility of 1,179 MW in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved.

Purpose of Study

On December 16, 2011 the Environmental Protection Agency ("EPA") issued their Mercury and Air Toxics Standards ("MATS") regulation. The MATS regulation is designed to reduce mercury, other metals and acid gas emissions from coal- and oil-fired power plants. The MATS regulation became effective on April 16, 2012, and the initial compliance deadline is three years after the effective date, or April 16, 2015. In order to comply with the MATS rule, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). The MATS rule does offer a one year extension, to be approved by the state permitting authority (Florida Department of Environmental Protection), if reliability issues warrant an extension.

In addition to the potential impacts of the MATS rule, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"), instead of repairing it as previously planned. The unit has been off-line since 2009, and has been previously modeled in the FRCC Databank as returning to service in 2015.
As a result of these events, and their potential impact(s) to the FRCC Region, the FRCC Planning Committee ("PC") directed the Transmission Working Group ("TWG") to perform an analysis determining the impact(s) to the Bulk Electric System ("BES") and the 69 kV transmission system within the FRCC.

The primary deliverables of the evaluation were:

- Determine whether a one year extension on the EPA's MATS compliance deadline is needed to ensure reliability.
- Assess the transmission reliability impact for the 2015 through 2017 timeframe and develop potential solutions.
- Evaluate the potential reliability benefits of a new combined cycle constructed in the vicinity of the existing Crystal River site, starting operations in summer of 2018.

Case Description and Sensitivities

The initial load flow cases selected for the evaluation were the 2012 FRCC Load Flow Databank (LFDB) cases (revision 1B), which were utilized for the FRCC's 2012 Long Range Study. These cases were slightly modified to reflect known assumptions and information about the system, including long-term resource and transmission plans, as well as correcting any issues that were identified during the Long Range Study effort.

The following years and loading conditions were selected for the analysis:

- Summer - 2015, 2016 (Peak and 60%), 2017, 2018
- Winter - 2015/16, 2016 /17

The following scenarios and sensitivities were analyzed:

- Base/Study scenarios – Generation economically dispatched by respective Balancing Authority area
  - Base cases include CR 1 & 2 and CR 3 on-line and fully dispatched
  - Study cases model CR 1 & 2 and CR 3 off-line with generation replaced with DEF available reserves. Minority owners of CR 3 replaced the generation from other resources.
- Base/Study scenarios – System response at the Florida / Southern import limit
  - Timeframe - summer 2016
  - Increased Southern to Florida transfer beyond firm commitments to 3,700 MW limit with remaining resources dispatched economically
- Polk Firm sensitivity – Stress Central Florida area
  - Timeframe - winter 2016/17 and summer 2017
  - Maximize all firm resources in the Polk area
    - FPL's Manatee unit evaluated at both economic dispatch and full output
- Crystal River site combined cycle sensitivity – DEF self-build alternative
  - Model a new 1,179 MW combined cycle resource assumed in-service by the summer of 2018, this correlates to DEF's latest Ten-Year Site Plan filed at the FPSC. The location is not specified in the Ten-Year Site Plan, so based on the FRCC PC study directive the unit was placed at the Crystal River plant with the combustion turbines connected to the 230 kV bus and the steam turbine connected to the 500 kV bus, with remaining DEF generation resources economically dispatched

- Unit Out scenarios (C3-Gens analysis)
  - Bayside 2, Crystal River 4, Crystal River 5, Fort Myers 2, Sanford 5 and Stanton 2, for winter 2015 and summer 2016.

Study Methodology

The TWG analysis was performed by conducting a power flow analysis under normal and various contingency conditions using Siemens Power System Simulator for Engineering ("PSS/E") and PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software program. All system elements 69 kV and above within the FRCC region were modeled for NERC Category A, B, and selected C contingency events using steady state methods. All branches' (including transformers and ties) thermal loadings were monitored to be within System Operating Limits ("SOL"). Thermal loadings greater than 100% of a facility's applicable rating that were materially aggravated (more than 3%) when compared to the reference case or thermal overloads that did not exist in the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement. Similarly, all system busses were monitored for applicable voltage criteria, including nuclear plant interface requirements. Voltages outside of transmission owner criteria that were materially lower (more than 2%) when compared to the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement.

The TWG performed the following steps for the analysis:

- Verified that under normal operating conditions (NERC Category A criteria), all facilities remained within applicable ratings.

- Performed a "Rate C" contingency screening in order to identify any conditions that would indicate potential SOL limitations which would require pre-contingency mitigation measures. Any potential limitation required a remedy before any further analysis, in order to represent the pre-contingency condition.

- Performed a NERC Category B contingency analysis on all Base and Study cases and sensitivities using the criteria described above.

- Performed NERC Category C (C2, C5, C3 Gen and C3 Lines) event analysis on all Base and Study cases and sensitivities using the criteria described above.

General Findings

The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is generally to reduce the two power injections from (1) the north to the Tampa Bay load area, and from (2) west central Florida to the western portions of the Orlando load area. Utilizing DEF's available reserves causes a shift in the power flow patterns with issues. The specific findings for the timeframes analyzed are discussed in subsequent sections.

Deliverable 1 - Findings and potential solutions for summer 2015 & winter 2015/16

DEF's System

The summer and winter of 2015 results indicate that with CR 1 & 2, and CR 3 retirement, the flow of power from the DEF Central Florida Substation into the Greater Orlando Area is reduced significantly. That coupled with the operation of the base load units at FPL's Sanford Plant and DEF's dispatch of Debary, results in significantly increased flows in the 230 kV corridor between the generation at Debary and Sanford, and the load to the south (West Greater Orlando Area). With the previously described conditions, this path experiences significant pre-contingency loading (99% of Rate A) and post-contingency thermal overloads. Additional post-contingency thermal overloads were also observed on other elements within DEF's system, which can be resolved using various switching mitigation procedures.

A combination of the previously stated 230 kV line rebuilds, significant 69 kV and 230 kV switching (sectionalizing), and significant re-dispatch is required to resolve the corridor overloads identified above. Since this corridor is used to transfer bulk power and to serve area load, switching alternatives are limited, and clearance windows would be short, making it very unlikely that the 230 kV rebuild lines could be completed prior to April 2015. In addition, re-dispatch options are also very limited due to the absence of the three base load resources at Crystal River that results in utilizing nearly all available reserves. What remains of the identified mitigations is a less desirable option to address the identified post-contingency corridor issues: a severe combination of 69 kV and 230 kV switching (sectionalizing), combined with limited re-dispatch at Debary.

If DEF were granted an extension to delay the shutdown of CR 1 & 2, the ability to run these units will resolve these significant issues on the system through April 2016.

Seminole Electric Cooperative, Inc.'s (SECI) System

During the 2012 Long Range Study, Seminole's 69 kV transmission line located in north Sumter County was projected to experience thermal overload conditions starting in the summer of 2016 and increasing slightly through the end of the planning horizon. Seminole's plan was to reconductor the 0.3 miles of 336 ACSR with 556 ACSR prior to the start of the summer of 2016 season. However, with the loss of CR 1 & 2, the thermal overload on the respective Seminole facility begins in the summer of 2015.

Seminole's original plan was to reconductor the 0.3 miles prior to the start of the summer 2016 season; however, with the assumption that CR 1 & 2 will be shutdown by 2015, Seminole would need to accelerate the reconductor project to be complete prior to the start of the summer 2015 season. This project could remain on its current schedule per the 2012 Long Range Study if DEF was granted an extension to delay the shutdown of CR1 & 2.

Tampa Electric Company's (TEC) System
Prior to proceeding with the study analysis, the cases were assessed for potential Rate C overloads by running all contingencies (B, C2, C5 & C3 Gens) against the Rate C. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic action schemes (i.e., SPS, UVLS, etc.).

The results for the summer 2015 and winter of 2015/16 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads under contingency events that are still outstanding. Each is fully mitigated with the ability to run CR 1 & 2.

Running CR 1 & 2 at the current generation capacity, as it had been projected in the 2012 LFDB models, resolves the overloads on many of the effected TEC facilities or reduces the impact on the thermal overloads on the remaining facilities, so that switching solutions would resolve the remaining overloads.

Determination

The TWG has determined that in the summer 2015 and winter 2015/16 scenarios, with the order to comply with the MATS regulation and subsequent shutdown of Crystal River unit 1 and unit 2, in addition to the announced retirement of Crystal River 3, severe reliability issues exist. The shutdown of CR 1 & 2 will cause new overloads and increase the magnitude of known contingency overloads, many of which cannot be remedied by existing operational procedures. These post-contingency overloads will require new transmission facilities to be constructed and/or existing transmission facilities to be rebuilt or re-conductored in order to accommodate new flow patterns that have not been previously observed.

The TWG finds that a one year extension for the operation of CR units 1 & 2 is justified and necessary to maintain the integrity and the reliability of the BES within the FRCC. This extension will allow additional time to construct transmission projects to resolve many of the issues and aid in mitigating significant post-contingency overloads allowing for operational procedures to be implemented.

Deliverable 2 - Transmission impacts and potential solutions in 2016 & 2017

DEF's System
The results for the summer and winter of 2016 and 2017 indicate significant overloads in:

- The 230 kV tie-line between Lakeland Electric (LAK) and DEF.
- The 230 kV corridor between the generation in the area of Debary (DEF) and Sanford (FPL) and the load to the south.

By summer 2016, DEF plans to rebuild the LAK / DEF 230 kV tie-line and remove the limiting elements to resolve the worst overloads in this area, although DEF will still need to use some switching mitigation procedures for other issues downstream. DEF also plans to eliminate its most limiting elements on the addition LAK / DEF 230 kV tie-line by April 2016.

Docket No. _____
Duke Energy Florida
Exhibit No. ____ (BMHB-1)

DEF is currently developing plans to have the corridor located north of Orland in southwest Seminole County rebuilt by summer of 2016. The rebuild of these segments in this corridor will improve area conditions, but until the last rebuild project is completed along this corridor, DEF will still have to depend on some combination of 69 kV and 230 kV switching and limited re-dispatch at Debary. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues on this corridor and significantly reduce the negative impact in many other areas as well.

As observed in the summer 2015 and winter 2015/16, some additional less significant thermal overloads remain in DEF's system, but can be satisfactorily resolved using various switching mitigation procedures.

TEC's System

Similar to the summer of 2015 and winter of 2015/16 cases, the summer of 2016 & 2017 and winter of 2016/17 cases were assessed for possible Rate C overloads. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic protection system (i.e., SPS, UVLS, etc.). s:

In addition to the BES Rate C overloads, the 69 kV system is also assessed for any potential Rate C overloads that may potentially impact the BES, but not required to be resolved prior to proceeding with the study analysis.. TEC would be able to address the 69 kV overloads by choosing to uneconomically increase the Pasco Cogen generation to its maximum as pre-contingency in all the cases.

The results for the summer of 2016 & 2017 and winter of 2016/17 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads that remain outstanding. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues and significantly reduce the negative impact in other areas as well.

Determination

In the 2016 and 2017 timeframe, severe reliability issues exist with the shutdown of CR 1 & 2. The most severe issues revolve around the Polk Firm and the Unit Out scenarios (most notably, Bayside 2). In these scenarios TWG has identified Rate C overloads and numerous post-contingency overloads in the TEC area for which mitigations have not yet been developed.

Deliverable 3 - Reliability impact of a new combined cycle built at Crystal River in 2018

TEC's System

The results for the summer of 2018 show the elimination of the Rate B and Rate C overloads shown in the previous cases with the exception of one 230 kV transmission line under a double contingency event in the Study scenario.

The effect of installing a combined cycle facility of 1,179 MW by the summer of 2018 in the Crystal River vicinity partially alleviates the thermal overload on TEC's 230 kV transmission line to 101% and a switching solution would resolve the remaining overload.

Determination

The TWG's evaluation of the transmission impact associated with the addition of a combined cycle facility of 1,179 MW by summer 2018 in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved

Effect on future studies

This study identified several concerns without providing firm resolutions for various contingency types and system conditions. For future studies that will have to incorporate the Crystal River shutdowns and retirements, including the FRCC Long Range Study, the issues identified in this analysis will need to have adequate remedies. Additionally, any future TSR/NITS or GISR/NRIS studies will be much more complex when starting with unresolved issues. There is one GISR already underway, and it is anticipated that more will be coming in the near future.

Duke Energy Florida, Inc.
Ten-Year Site Plan

April 2014

2014-2023

Submitted to:
Florida Public Service Commission

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CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined Cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. Duke Energy Florida, Inc.'s TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

DEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning DEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**

  This chapter provides an overview of DEF's generating resources as well as the transmission and distribution system.

- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**

  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.

- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**

  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.

- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**

  Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, Inc. (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.7 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of Saint Petersburg and Clearwater. DEF is interconnected with 22 municipal and nine rural electric cooperative systems. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 13,000 circuit miles of underground distribution cable.

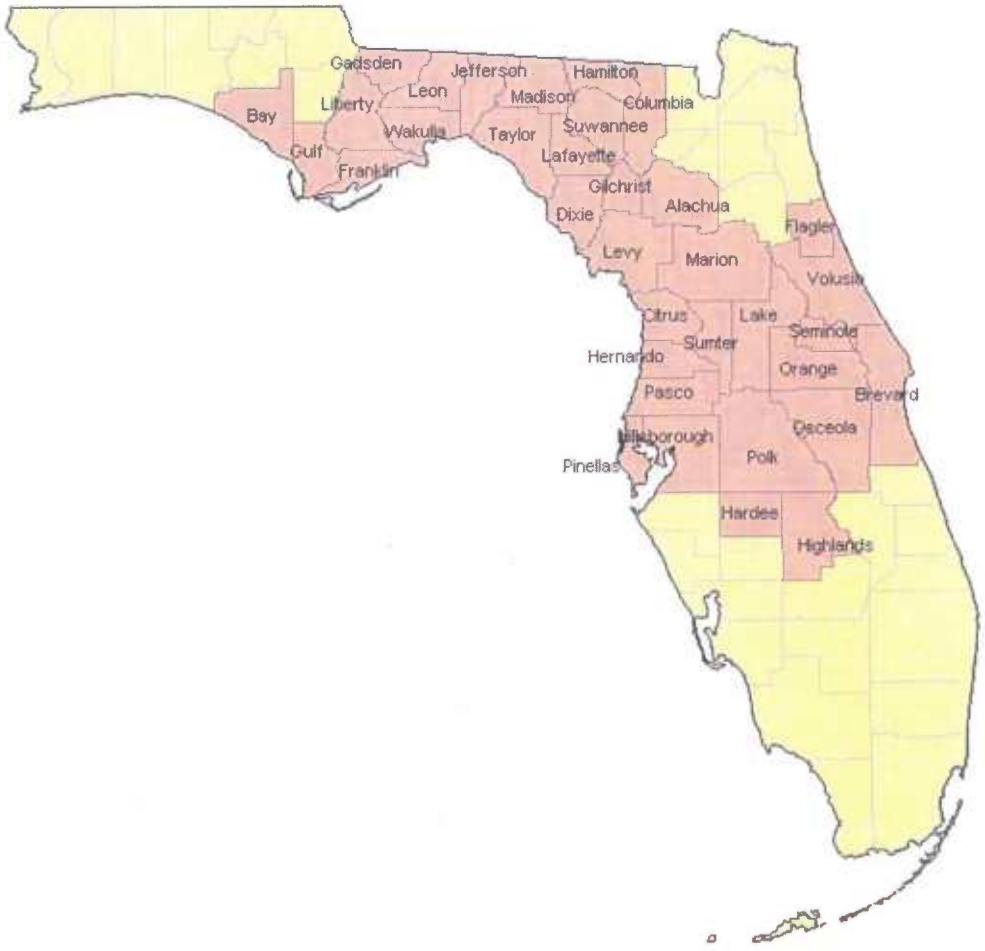
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 410,000 customers participated in the residential Energy Management program during 2013, contributing about 652 MW of winter peak-shaving capacity for use during high load periods. DEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs.

TOTAL CAPACITY RESOURCE

As of December 31, 2013, DEF had total summer capacity resources of 11,258 MW consisting of installed capacity of 9,141 MW and 2,117 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				FUEL		FUEL TRANSPORT			COM'L IN-SERVICE	EXPECTED RETIREMENT	GEN. MAX. NAMEPLATE	NET CAPABILITY SUMMER	NET CAPABILITY WINTER
PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	PRI.	ALT.	PRI.	ALT.	ALT. FUEL DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	484	506
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	490	511
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66		440,550	370	372
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69		523,800	499	503
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	710	721
SUWANNEE RIVER	1	SUWANNEE	ST	NG		PL		***	11/53	*****	34,500	28	28
SUWANNEE RIVER	2	SUWANNEE	ST	NG		PL		***	11/54	*****	37,500	29	28
SUWANNEE RIVER	3	SUWANNEE	ST	NG		PL		***	10/56	*****	75,000	71	73
												3,393	**3,463**
COMBINED-CYCLE													
BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	***	6/09		1,253,000	1,160	1,185
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	***	4/99		546,500	462	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	***	12/03		548,250	490	563
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	***	11/05		561,000	488	564
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	***	12/07		610,000	472	544
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	205	231
												3,277	**3,615**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	***	12/68	******	33,790	24	35
AVON PARK	P2	HIGHLANDS	GT	DFO		TK		***	12/68	******	33,790	24	35
BARTOW	P1, P3	PINELLAS	GT	DFO		WA		***	5/72, 6/72		111,400	86	108
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	42	57
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	49	61
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA		***	4/73		226,800	174	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK		***	12/75-4/76		401,220	310	381
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	***	10/92		345,000	247	287
DEBARY	P10	VOLUSIA	GT	DFO		TK		***	10/92		115,000	80	95
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	***	3/69, 4/69	******	67,580	45	45
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	***	12/70, 1/71	******	85,850	60	71
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK		***	5/74		340,200	286	372
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	10/93		460,000	328	379
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK		***	1/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	12/00		345,000	229	276
RIO PINAR	P1	ORANGE	GT	DFO		TK		***	11/70	******	19,290	12	15
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	***	10/80, 11/80		122,400	104	127
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK		***	10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK		***	10/70	******	38,580	20	26
TURNER	P3	VOLUSIA	GT	DFO		TK		***	8/74	******	71,200	53	77
TURNER	P4	VOLUSIA	GT	DFO		TK		***	8/74		71,200	58	78
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			1/94		43,000	46	47
												2,471	**3,031**
										TOTAL RESOURCES (MW)		**9,141**	**10,109**

** THE 143 MW SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) IS OWNED BY GEORGIA POWER COMPANY

*** APPROXIMATELY 2 TO 8 DAYS OF OIL USE TYPICALLY TARTGETED FOR ENTIRE PLANT.

***** SUWANNEE STEAM UNITS ESTIMATED TO BE SHUTDOWN BY 6/2018.

****** PEAKERS at AVON PARK, RIO PINAR, TURNER P1&P2 ARE ESTIMATED TO BE PUT IN COLD STAND-BY OR RETIRED BY 6/2016 WITH TURNER P3 BY 12/2014 AND HIGGINS BY 6/2020.

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). DEF's customer growth is expected to average 1.4 percent between 2014 and 2023, which is more than the ten-year historical average of 0.8 percent. County population growth rate projections from the University of Florida's Bureau of Economic and Business Research (BEBR) were incorporated into this projection. The severe housing crisis witnessed both nationwide and in Florida since 2007 has dampened the DEF historical ten-year growth rate significantly as total customer growth turned negative for a twenty-one month period during 2008, 2009 and 2010. Economic conditions going forward look more amenable to improved customer growth due to lower housing prices, improved housing affordability and a large retiring baby-boomer population.

Net energy for load (NEL) dropped by an average 1.2 percent per year between 2004 and 2013 due primarily to the economic recession and the weak economic recovery that followed. Sales for Resale in 2013 were only 35% of their 2004 level. Mild winter weather conditions early in 2013 and above normal rainfall over the summer also contributed to the results. The 2014 to 2023 period is expected to improve by an average growth rate of 1.5 percent per year due to expected higher population and economic growth that drives the retail jurisdiction back to more normal NEL growth rates. Going forward, projected NEL growth continues to reflect the FPSC approved DSM energy savings targets. Wholesale NEL is expected to increase by 33% over the ten year horizon.

Summer net firm demand declined an average 0.3 percent per year during the last ten years, mostly driven by a wholesale load that was nearly 50% below the average of the previous nine summers. The projected ten year period summer net firm demand growth rate of 1.6 percent is primarily driven by higher population improving net firm retail demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided:

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1	History and Forecast of Base Summer Peak Demand (MW)
3.2	History and Forecast of Base Winter Peak Demand (MW)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

DUKE ENERGY FLORIDA

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
2004	3,339,460	2.447	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,427,860	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,505,058	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,531,483	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,727	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,937	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,813	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,633,611	2.491	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,633,838	2.480	18,508	1,465,169	12,632	11,718	163,671	71,594
2014	3,700,173	2.471	18,574	1,497,280	12,405	11,617	167,106	69,519
2015	3,736,060	2.456	18,840	1,520,916	12,387	11,766	169,628	69,364
2016	3,777,512	2.446	19,179	1,544,620	12,417	12,015	172,186	69,779
2017	3,818,761	2.435	19,494	1,568,452	12,429	12,200	174,750	69,814
2018	3,861,879	2.427	19,833	1,591,324	12,463	12,297	177,209	69,393
2019	3,906,298	2.422	20,086	1,612,908	12,453	12,499	179,511	69,628
2020	3,949,461	2.417	20,351	1,634,061	12,454	12,735	181,753	70,068
2021	3,992,349	2.413	20,605	1,654,509	12,454	12,939	183,909	70,355
2022	4,033,775	2.409	20,906	1,674,417	12,486	13,239	185,998	71,178
2023	4,075,604	2.407	21,199	1,693,168	12,520	13,457	187,949	71,599

DUKE ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		INDUSTRIAL					
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,176
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	3,819	2,668	1,431,409	0	26	3,341	39,282
2008	3,786	2,587	1,463,471	0	26	3,276	38,555
2009	3,285	2,487	1,320,869	0	26	3,230	37,824
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,370	1,352,743	0	25	3,159	36,616
2014	3,153	2,324	1,356,713	0	24	3,123	36,491
2015	3,173	2,307	1,375,379	0	24	3,145	36,948
2016	3,188	2,293	1,390,318	0	24	3,178	37,584
2017	3,158	2,277	1,386,913	0	23	3,198	38,073
2018	3,251	2,259	1,439,132	0	23	3,220	38,624
2019	3,503	2,241	1,563,141	0	23	3,239	39,350
2020	3,618	2,224	1,626,799	0	22	3,257	39,983
2021	3,564	2,208	1,614,130	0	22	3,274	40,404
2022	3,535	2,192	1,612,682	0	22	3,289	40,991
2023	3,490	2,176	1,603,860	0	22	3,301	41,469

DUKE ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,507	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	5,598	2,753	47,633	24,010	1,632,368
2008	6,619	2,484	47,658	24,738	1,638,935
2009	3,696	2,604	44,124	24,993	1,630,195
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,543	1,656,753
2014	936	2,374	39,801	25,904	1,692,614
2015	974	2,568	40,490	26,079	1,718,930
2016	1,024	2,490	41,098	26,233	1,745,332
2017	795	2,507	41,375	26,369	1,771,848
2018	767	2,604	41,995	26,489	1,797,281
2019	1,046	2,617	43,013	26,596	1,821,256
2020	1,270	2,745	43,998	26,689	1,844,727
2021	1,243	2,772	44,419	26,772	1,867,398
2022	1,244	2,635	44,870	26,847	1,889,454
2023	1,244	2,746	45,459	26,913	1,910,206

DUKE ENERGY FLORIDA

SCHEDULE 3.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
2004	9,583	1,071	8,512	531	331	185	39	163	110	8,224
2005	10,350	1,118	9,232	448	310	203	38	166	110	9,074
2006	10,147	1,257	8,890	329	307	222	37	170	66	9,016
2007	10,931	1,544	9,387	334	291	239	45	177	110	9,735
2008	10,592	1,512	9,080	500	284	255	66	192	110	9,186
2009	10,853	1,618	9,235	262	291	271	84	211	110	9,624
2010	10,238	1272	8,966	271	304	296	96	232	110	8,929
2011	9,968	934	9,034	227	317	327	97	255	110	8,636
2012	9,783	1080	8,703	262	326	355	100	278	124	8,338
2013	9,581	581	9,000	334	332	384	101	297	124	8,008
2014	10,359	804	9,555	254	337	411	105	308	132	8,812
2015	10,631	806	9,825	256	342	434	110	316	132	9,042
2016	10,775	658	10,117	255	347	455	114	323	132	9,149
2017	10,998	587	10,411	256	383	473	118	330	132	9,307
2018	11,169	587	10,582	263	388	488	122	336	132	9,440
2019	11,620	837	10,783	310	393	503	127	342	132	9,813
2020	11,795	837	10,958	332	398	520	131	346	132	9,935
2021	11,842	737	11,104	333	403	536	135	351	132	9,952
2022	11,985	738	11,247	333	408	550	139	355	132	10,067
2023	12,118	738	11,380	333	413	564	143	359	132	10,173

Historical Values (2004 - 2013):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2014 - 2023):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
2003/04	9,323	1,167	8,156	498	788	342	26	123	262	7,284
2004/05	10,830	1,600	9,230	575	779	371	26	123	283	8,673
2005/06	10,698	1,467	9,231	298	762	413	26	124	239	8,835
2006/07	9,896	1,576	8,320	304	671	453	26	126	262	8,055
2007/08	10,964	1,828	9,136	234	763	487	34	132	278	9,036
2008/09	12,092	2,229	9,863	268	759	522	71	147	291	10,034
2009/10	13,698	2,189	11,509	246	651	567	80	162	322	11,670
2010/11	11,347	1,625	9,722	271	661	633	94	179	214	9,295
2011/12	9,715	905	8,810	186	639	681	96	202	206	7,706
2012/13	9,105	831	8,274	248	652	744	97	219	193	6,952
2013/14	11,126	895	10,231	237	661	796	101	233	228	8,870
2014/15	11,476	1,376	10,099	238	670	845	105	241	243	9,133
2015/16	11,779	1,378	10,401	238	679	887	110	249	246	9,371
2016/17	11,788	1,088	10,700	238	706	927	114	256	249	9,298
2017/18	12,093	1,088	11,005	245	715	956	118	263	252	9,544
2018/19	12,281	1,088	11,193	288	724	984	122	269	254	9,639
2019/20	12,690	1,338	11,351	309	733	1,018	127	275	256	9,972
2020/21	12,827	1,338	11,489	310	742	1,049	131	278	257	10,059
2021/22	12,958	1,339	11,619	310	751	1,079	135	281	258	10,143
2022/23	13,083	1,339	11,745	310	760	1,106	139	285	259	10,224

Historical Values (2004 - 2013):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2014 - 2023):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
2004	46,834	426	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,475	455	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,399	484	365	509	39,432	4,220	2,389	46,041	52.1
2007	49,310	511	387	779	39,282	5,598	2,753	47,633	52.3
2008	49,208	543	442	565	38,556	6,619	2,483	47,658	53.1
2009	45,978	583	492	779	37,824	3,696	2,604	44,124	44.5
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.0
2013	43,150	778	736	864	36,616	1,488	2,668	40,772	53.0
2014	42,249	821	763	864	36,491	936	2,374	39,801	51.2
2015	43,047	857	787	913	36,948	974	2,568	40,490	50.6
2016	43,714	890	810	916	37,584	1,024	2,490	41,098	49.9
2017	44,037	918	831	913	38,073	795	2,507	41,375	50.8
2018	44,702	944	850	913	38,624	767	2,604	41,995	50.2
2019	45,763	969	868	913	39,350	1,046	2,617	43,013	50.9
2020	46,797	996	887	916	39,983	1,270	2,745	43,998	50.2
2021	47,258	1,021	905	913	40,404	1,243	2,772	44,419	50.4
2022	47,749	1,044	922	913	40,991	1,244	2,635	44,870	50.5
2023	48,377	1,067	938	913	41,469	1,244	2,746	45,459	50.8

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration.

** Load Factors for historical years are calculated using the actual winter peak demand except the 2004, 2007, 2012 and 2013 historical load factors which are based on the actual summer peak demand which became the annual peaks for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

DUKE ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2013		FORECAST 2014		FORECAST 2015	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	5,877	2,881	9,973	3,166	10,257	3,213
FEBRUARY	8,032	2,746	8,454	2,713	9,127	2,766
MARCH	7,856	3,031	7,479	2,879	8,188	2,936
APRIL	7,153	3,166	7,537	2,954	7,781	3,008
MAY	7,863	3,460	8,467	3,560	8,694	3,616
JUNE	8,524	3,965	9,021	3,749	9,246	3,810
JULY	8,352	3,983	9,327	3,953	9,562	4,012
AUGUST	8,776	4,283	9,509	3,993	9,750	4,058
SEPTEMBER	8,446	3,861	8,778	3,728	8,984	3,790
OCTOBER	7,645	3,517	8,192	3,330	8,472	3,390
NOVEMBER	6,418	2,912	6,697	2,738	6,902	2,804
DECEMBER	5,826	2,967	8,764	3,038	8,879	3,087
TOTAL		40,772		39,801		40,490

NOTE: Recorded Net Peak demands and System requirements include off-system wholesale contracts.

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. DEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one fuel source. Near term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth and natural gas generation costs reflect relatively attractive natural gas commodity pricing.

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,543	4,792	4,521	5,099	4,709	5,443	4,951	4,431	3,314	3,253	2,863	3,230
(3)	RESIDUAL	TOTAL	1,000 BBL	89	251	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	89	251	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	160	132	128	145	159	116	117	66	96	69	93	166
(9)		STEAM	1,000 BBL	60	55	61	61	54	49	31	12	31	33	45	39
(10)		CC	1,000 BBL	1	8	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	99	69	66	84	105	67	86	54	64	36	48	126
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	187,251	177,196	185,946	183,135	188,841	185,881	196,042	211,855	232,439	245,117	258,700	256,669
(14)		STEAM	1,000 MCF	26,837	23,404	31,406	37,531	36,652	26,744	25,644	26,128	23,891	24,146	24,876	28,004
(15)		CC	1,000 MCF	155,717	150,875	148,761	138,981	142,519	149,678	160,865	177,949	200,579	213,835	226,668	219,394
(16)		CT	1,000 MCF	4,697	2,917	5,779	6,623	9,669	9,459	9,533	7,778	7,969	7,135	7,156	9,271
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	0	0	12,711	12,734	18,515	14,152	13,659	13,607	14,812	5,519	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	0	0	7,403	8,894	10,318	6,071	6,028	5,518	5,312	4,373	4,938	7,123
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	0	0	221	225	105	0	0	0	0	0	0	0

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,558	1,409	709	854	989	578	577	529	495	408	457	687
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,003	10,577	9,816	11,072	10,078	11,776	10,826	9,272	6,772	6,617	5,802	6,585
(4)	RESIDUAL	TOTAL	GWh	46	127	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	46	127	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	104	93	27	35	43	27	35	23	27	16	21	57
(10)		STEAM	GWh	63	58	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	1	7	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	39	28	27	35	43	27	35	23	27	16	21	57
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,997	23,061	24,337	23,621	24,374	24,194	25,818	28,468	31,855	33,840	35,846	35,370
(15)		STEAM	GWh	2,175	1,951	2,738	3,349	3,264	2,235	2,159	2,240	2,006	2,038	2,136	2,430
(16)		CC	GWh	21,469	20,893	21,037	19,641	20,183	21,038	22,732	25,465	29,061	31,087	32,998	32,032
(17)		CT	GWh	353	217	562	631	927	921	927	763	788	715	711	908
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,767	2,886	1,421	1,444	1,529	1,527	1,533	1,526	1,506	1,507	1,498	1,505
	RENEWABLES		GWh	1,183	1,132	1,301	1,260	1,277	1,279	1,285	1,280	1,254	1,253	1,245	1,256
	IMPORT FROM OUT OF STATE		GWh	1,559	1,546	2,191	2,203	2,809	1,995	1,921	1,915	2,089	777	0	0
	EXPORT TO OUT OF STATE		GWh	-4	-59	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	41,213	40,772	39,801	40,490	41,098	41,375	41,995	43,013	43,998	44,419	44,870	45,459

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		%	3.8%	3.5%	1.8%	2.1%	2.4%	1.4%	1.4%	1.2%	1.1%	0.9%	1.0%	1.5%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	24.3%	25.9%	24.7%	27.3%	24.5%	28.5%	25.8%	21.6%	15.4%	14.9%	12.9%	14.5%
(4)	RESIDUAL	TOTAL	%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(10)		STEAM	%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	58.2%	56.6%	61.1%	58.3%	59.3%	58.5%	61.5%	66.2%	72.4%	76.2%	79.9%	77.8%
(15)		STEAM	%	5.3%	4.8%	6.9%	8.3%	7.9%	5.4%	5.1%	5.2%	4.6%	4.6%	4.8%	5.3%
(16)		CC	%	52.1%	51.2%	52.9%	48.5%	49.1%	50.8%	54.1%	59.2%	66.1%	70.0%	73.5%	70.5%
(17)		CT	%	0.9%	0.5%	1.4%	1.6%	2.3%	2.2%	2.2%	1.8%	1.8%	1.6%	1.6%	2.0%
(18)	OTHER 2/														
	QF PURCHASES		%	6.7%	7.1%	3.6%	3.6%	3.7%	3.7%	3.6%	3.5%	3.4%	3.4%	3.3%	3.3%
	RENEWABLES		%	2.9%	2.8%	3.3%	3.1%	3.1%	3.1%	3.1%	3.0%	2.8%	2.8%	2.8%	2.8%
	IMPORT FROM OUT OF STATE		%	3.8%	3.8%	5.5%	5.4%	6.8%	4.8%	4.6%	4.5%	4.7%	1.7%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

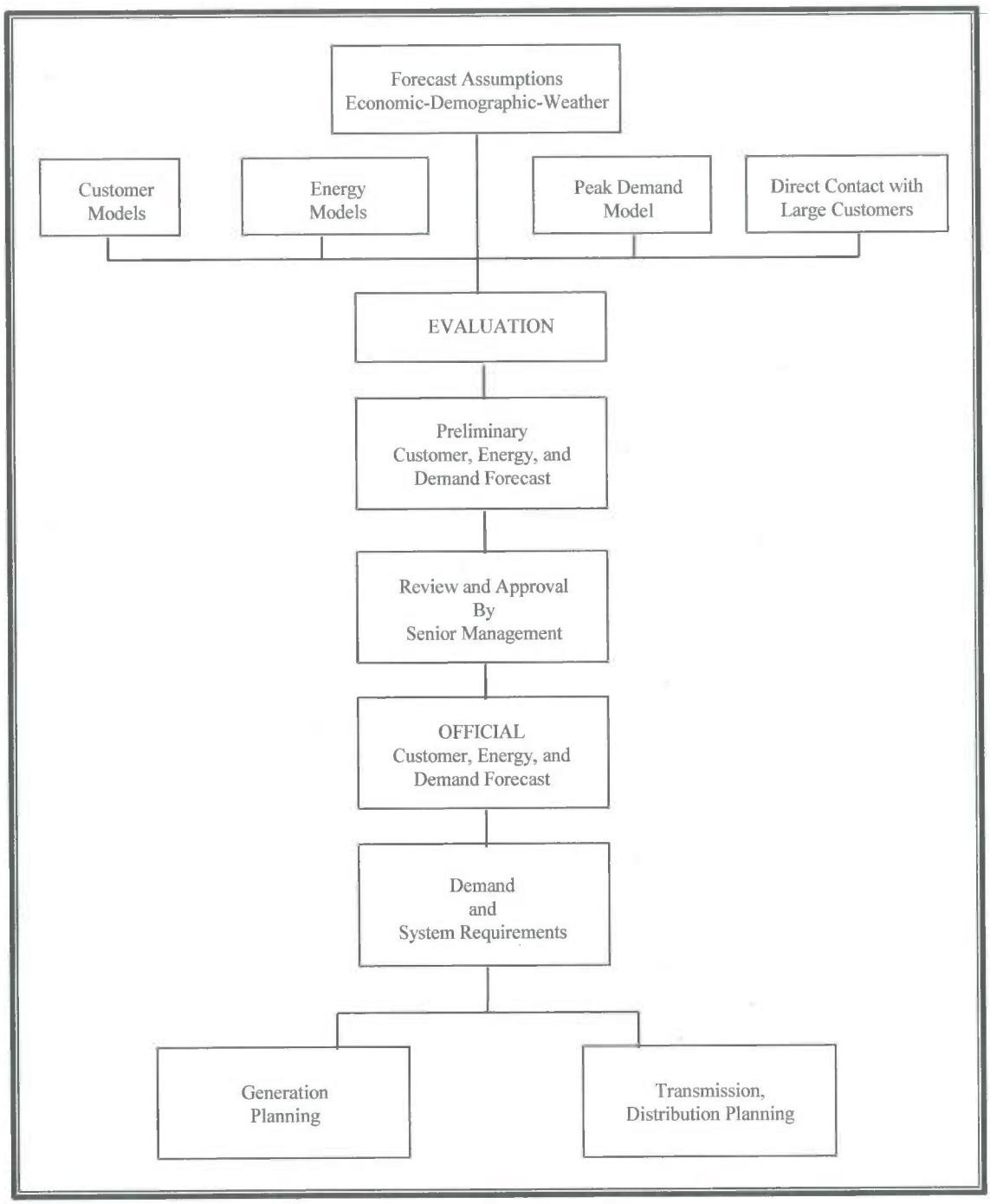
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 10-year average of conditions at the St Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 10-year average of the billing cycle weighted monthly heating and cooling degree-days. The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the ten year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day values begin to accumulate. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the same three weather stations. The remaining months of the year may use less than 30 years if an historical monthly peak occurred during an unexpected time of day due to unusual weather.

2. Historical population, household and average household size estimates by Florida county produced by the BEBR at the University of Florida as published in "Florida Population Studies", Bulletin No. 65 (March 2013). The projected change in Florida average household size from Moody's Analytics provided the basis for the 29 county household projection used in the development of the customer forecast. National and Florida economic projections produced by Moody's Analytics in their July 2013 forecast provided the basis for development of the DEF customer and energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Three major customers accounted for exactly 33 percent of the industrial class MWh sales in 2013. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward,

global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. The DEF forecast calls for an increase in annual electric energy consumption due to a new mine opening later in this decade. A risk to this projection lies in the price of energy, which is a major cost of both mining and producing phosphoric fertilizers. Fuel charges embedded in DEF's rates versus competitors' rates play a role as to where a mining customer directs output from self-owned generation facilities. This can reduce DEF industrial sales.

4. DEF supplies load and energy service to wholesale customers on a "full" and "partial" requirement basis. Full requirements (FR) customers demand and energy are assumed to grow at a rate that approximates their historical trend. However, the impact of the current recession has reduced short term growth expectations. Contracts for this service include the cities of Chattahoochee, Mt. Dora and Williston. Partial requirements (PR) customers load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Reedy Creek Improvement District (RCID), Seminole Electric Cooperative, Inc. (SECI), and the cities of New Smyrna Beach and Homestead.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently offered DSM programs.

7. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. This projection incorporates an increase of over 15 MW of self-service generation in 2013 from two customers. DEF will supply the supplemental load of self-service cogeneration customers. While DEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place. FR customers are typically assumed to renew their contracts with DEF except those who have termination provisions and have given their notice to terminate. PR contracts are typically projected to terminate as terms reach their expiration date.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2013 as the nation waited for stronger signs of growth. Most economic indicators pointed to better days ahead but Washington policy-makers continued to debate pro-growth versus deficit reduction strategies which prolonged uncertainty for consumers, employers and capital investment decision-makers. Consumer confidence and sentiment surveys improved, reflecting the lower unemployment rate and record setting stock market indexes. In Florida, these trends were tempered by continued high foreclosure rates and an expected sixth straight year of lower Statewide median household real income from its 2007 peak.

The DEF forecast incorporates the economic assumptions implied in the Moody's Analytics U.S. and Florida forecasts with some minor tempering to its short term optimism. This view suggests that a de-leveraging American consumer will begin to spend again, feeling more secure about the outlook. The newfound abundance of American energy supplies, creating additional job growth and low natural gas prices, is expected to improve the country's competitive advantage in several manufacturing sectors. An improved manufacturing sector is well displayed in many parts across the U.S. The domestic economic picture will, however, continue to feel the drag from a weak Euro-Zone and other emerging economies. This will be reflected in lower short term growth from what has been a surprising source of U.S. GDP growth: American exports.

The debt bubble that set the conditions for the Great Recession and the lingering effects of the recession have created many economic imbalances that many now believe will result in a longer time to return to equilibrium than the ordinary recession. Signs of optimism do exist, however.

DEF customer growth increased by more than 20,000 in December 2013 from December 2012. The anticipated influx of retiring baby-boomers may just be starting to be reflected in the data.

Energy prices are expected to remain in a tight range through the forecast due to increased supplies of both fossil fuels and renewables. The potential for a carbon tax or other monetization of carbon restrictions remains on the horizon in the 2020 period and is incorporated into this forecast's electric price projection. No disruption in global supplies of energy or new environmental findings over the safety of extracting fossil fuels are expected in the forecast horizon.

Also incorporated in this energy forecast is a projection of customer-owned solar photovoltaic generation and electric vehicle ownership. The net energy impact of both are expected to result in only marginal impacts to the forecasted energy growth.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, interruptible service and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Analytics and the University of Florida's BEBR. Internal company forecasts are used for projections of electricity price, weather conditions,

and the length of the billing month. The incorporation of residential and commercial "end-use" energy have been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company's Market Research department and the Energy Information Agency (EIA), along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an easier explanation of usage levels and changes in weather-sensitivity over time. The "bundling" of 19 residential appliances into "heating", "cooling" and "other" end uses form the basis of equipment-oriented drivers that are interacted with the typical exogenous factors as real median household income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with households within DEF's 29 county service area. County level population projections for counties in which DEF serves residential customers are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. As in the residential sector, these variables are interacted with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation

- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing

employment interacted with the Florida industrial production index, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out, start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon.

Street Lighting

Electricity sales to the street and highway lighting class have remained flat for years but have declined of late. A continued decline is expected as improvements in lighting efficiency are projected. The number of accounts, which has dropped by more than one-third since 1995 due to most transferring to public authority ownership, is expected to decline further before leveling off in the intermediate term. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow within the size of the service area. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e. public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use in the billing months of January, July, and August. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or sales for resale, customer of DEF contracting to purchase base, intermediate and peaking stratified load over varying time periods over the forecast horizon. The municipal sales for resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Three customers in this class, Chattahoochee, Mt. Dora, and Williston, are municipalities whose full energy requirements are supplied by DEF. Energy projections for full requirement customers grow at a rate that approximates their historical trend with additional information coming from the respective city officials. DEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, and another power provider, RCID. In each case, these customers contract with DEF for a specific level and type of stratified capacity needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load and expected fuel prices.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF's coincident system peak is separated into five major components. These components consist of potential firm retail load, interruptible and curtailable tariff non-firm load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

Potential firm retail load refers to projections of DEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the

size of DEF's firm retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in load control reductions. Seasonal peaks are projected using the historical seasonal peak hour regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected. Energy conservation and direct load control estimates are consistent with DEF's DSM goals that have been established by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of retail monthly peak demand figures.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of monthly demands. The Full Requirement municipal demand forecast is estimated for individual cities using historically trended growth rates adjusted for current economic conditions.

DEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon as it has historically. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from DEF's large industrial accounts by account executives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

CONSERVATION

On August 16, 2011, the PSC issued Order No. PSC-11-0347-PAA-EG, Modifying and Approving the Demand Side Management Plan of DEF (formerly known as Progress Energy Florida, Inc.). In this Order, the FPSC modified DEF's DSM Plan to consist of those existing programs in effect as of the date of the Order.

The following tables show the 2010 through 2013 achievements from DEF's existing set of DSM programs.

Residential Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	43	85	58
2011	82	160	110
2012	115	229	156
2013	140	274	195

Commercial Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	36	32	66
2011	65	61	132
2012	92	81	196
2013	118	101	237

Total Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	79	116	124
2011	148	221	242
2012	208	310	352
2013	258	375	432

DEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs that will continue to be offered through 2014. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. A brief description of each of the currently offered DSM programs is provided below.

In 2012, DEF received administrative approval of revisions to four programs as a result of changes to the Florida Building Code: Home Energy Improvement, Residential New Construction, Business New Construction and Better Business. The Building Code changes resulted in increased minimum efficiency levels which resulted in an increase in the baseline efficiency level from which DEF provides incentives. The revisions to the four programs are incorporated in the descriptions below.

In 2013, the increased efficiency standards impacted participation in DEF's approved DSM programs as measures that previously were eligible for incentives became required standards ineligible for incentives. The higher performance requirements established by the changes to the Florida Building Code, along with the state and federal minimum efficiency standards for residential appliances and commercial equipment, resulted in a reduction of demand and energy savings from DEF's DSM programs. As the U.S. Department of Energy (DOE) continues the implementation of increased energy efficiency standards for residential and commercial end-uses, the amount of demand and energy savings captured by DEF's DSM programs will decrease. As DEF continues its planning process in the ongoing DSM goals docket, the impacts of future implementation of state building code and federal appliance standards will be incorporated into its DSM goal proposals.

DEF's CURRENTLY APPROVED DSM PROGRAMS:

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides residential customers with an analysis of their current energy use and provides recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers DEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-Completed Mail-In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit – a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III); and Type 7: Student Mail In Audit - a student-completed audit. The Home Energy Check program serves as the foundation of the Home Energy Improvement program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement

The Home Energy Improvement Program is the umbrella program that serves to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps. Additional measures within this program include spray-in wall insulation, central AC 14 Seasonal Energy Efficiency Ratio (SEER) non-electric heat, and proper sizing of high efficiency Heating, Ventilation and Air Conditioning (HVAC) systems, HVAC commissioning, reflective roof coating for manufactured homes, reflective roof for single-family homes, window film or screen, and replacement windows.

Residential New Construction

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the U.S. Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. Additional measures within the Residential New Construction program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler, and energy recovery ventilation.

Low Income Weatherization Assistance

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver

This program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead, refrigerator coil brush, HVAC filters, and weatherization measures (i.e. weather stripping, door sweeps, etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

Residential Energy Management (EnergyWise)

This program allows DEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio-controlled switches installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh per month.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of a free walk-through audit and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues as well as incentives on efficiency measures. The Better Business program promotes energy efficient HVAC, building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation, and Energy Star cool roof coating products), demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the State of Florida energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives are available for high efficiency HVAC equipment, energy recovery ventilation, Energy Star cool roof coating products, demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal energy storage and window film or screen.

Innovation Incentive

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for DEF customers. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak demand and/or energy, but are not addressed by other programs. Energy efficiency opportunities are identified by DEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to DEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces DEF's demand during peak or emergency conditions. As described in DEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent structures and utilized for the following purposes: 1) water heater(s), 2) central electric heating system(s), 3) central electric cooling system(s), and or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation

This demand control program reduces DEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability of at least 50 kW, and are willing to reduce their demand when DEF deems it necessary. Customers participating in the Standby Generation program receive a monthly credit on their electric bills according to their demonstrated ability to reduce demand at DEF's request.

Interruptible Service

This direct load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. DEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for the ability to interrupt load, customers participating in the Interruptible Service program receive a monthly credit applied to their electric bills.

Curtailable Service

This load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001(5)(f), Florida Administration Code). In accordance with the rule, the Technology Development program facilitates the research of innovative technologies and continued advances within the energy industry. DEF will undertake certain development, educational and demonstration projects that have potential to become DSM programs. Examples of such projects include the evaluation of Premise Area Networks that provide an increase in customer awareness of efficient energy usage while advancing demand response capabilities. Additional projects have included the evaluation of off-peak generation with energy storage for on-peak demand consumption, small-scale wind and smart charging for plug-in hybrid electric vehicles. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

DEMAND-SIDE RENEWABLE PORTFOLIO

Solar Water Heating for the Low-income Residential Customers Pilot

This pilot program is designed to assist low-income families with energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. DEF collaborates with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system is provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This pilot program encourages residential customers to install new solar thermal water heating systems on their residence with the requirement for customers to participate in our residential Energy Management program (EnergyWise). Participants receive a one-time $550 rebate designed to reduce the upfront cost of the renewable energy system, plus a monthly bill credit associated with their participation in the residential Energy Management program.

Residential Solar Photovoltaic Pilot

This pilot encourages residential customers to install new solar photovoltaic (PV) systems on their home. A DEF audit is required prior to system installation to qualify for this rebate. Participating customers will receive a one-time rebate of up to $20,000 to reduce the initial investment required to install a qualified renewable solar PV system. The rebate is based on the wattage of the PV (DC) power rating.

Commercial Solar Photovoltaic Pilot

This pilot encourages commercial customers to install new solar PV systems on their facilities. A DEF energy audit is required prior to system installation to qualify for this rebate. The program provides participating commercial customers with a tiered rebate to reduce the initial investment in a qualified solar PV system. The rebate is based on the PV (DC) power rating of the unit installed. The total incentives per participant will be limited to $130,000, based on a maximum installation of 100 kW.

Photovoltaic For Schools Pilot

This pilot is designed to assist schools with energy costs while promoting energy education. This program provides participating public schools with new solar photovoltaic systems at no cost to the school. The primary goals of the program are to:

- Eliminate the initial investment required to install a solar PV system
- Increase renewable energy generation on DEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in DEF communities and schools

The program will be limited to an annual target of one system with a rating up to 100 KW installed on a post secondary public school and ten 10 KW systems with battery backup option installed on public K-12 schools, preferably serving as emergency shelters.

Research and Demonstration Pilot

The purpose of this pilot program is to research technology and establish Research and Design initiatives to support the development of renewable energy pilot programs. Demonstration projects will provide real-world field testing to assist in the development of these initiatives. The program will be limited to a maximum annual expenditure equal to 5% of the total Demand-Side Renewable Portfolio annual expenditures.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2013 DEF had a summer total capacity resource of 11,258 MW (see Table 3.1). This capacity resource includes fossil steam (3,393 MW), combined-cycle plants (3,277 MW), combustion turbines (2,471 MW; 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (413 MW), independent power purchases (1,114 MW), and non-utility purchased power (590 MW). Table 3.2 presents DEF's firm capacity contracts with Renewable and Cogeneration Facilities.

Demand-Side Programs

Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. DEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with DEF. In its planning process, DEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued

an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site. DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan. DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews. DEF expects to file formal petitions regarding resource selections resulting from these evaluations during 2014.

The promulgation of the Mercury and Air Toxics Standards (MATS) by EPA in April of 2012 presents new environmental requirements for the DEF units at Anclote, Suwannee and Crystal River.

- The three steam units at Suwannee are capable of operation on both natural gas and residual oil. These units will be able to comply with the MATS rule by ceasing operation on residual oil prior to the April 2015 compliance date. Residual oil was removed from the site in 2013.
- DEF is continuing to execute projects at the Anclote facility to convert the two residual oil fired units there to 100% firing on natural gas. These environmental control upgrades are expected to enable these two units to operate in compliance with the requirements of the MATS. Following completion of the project in 2014, DEF will conduct final tests to confirm performance levels.
- Crystal River Units 1 and 2 are not capable of meeting the emissions requirements for MATS in their current configuration and using the current fuel. In addition, under the terms of the revised air permit, in accordance with the State Implementation Plan for compliance with the requirements of the Clean Air Visible Haze Rule, these units are required to cease coal fired operation by the end of 2020 unless scrubbers are installed prior to the end of 2018.
- DEF has received a one year extension of the deadline to comply with MATS for Crystal River Units 1 and 2 from the Florida Department of Environmental Protection. This extension was granted to provide DEF sufficient time to complete projects necessary to

enable interim operation of those units in compliance with MATS during the 2016 – 2020 period.

- DEF anticipates burning MATS compliance coals in Crystal River Units 1 and 2 beginning no later than April 2016. Although specific dates have not been finalized, DEF anticipates retiring the Crystal River Units 1 and 2 in 2018 in coordination with the 2018 Citrus Combined Cycle operations.
- Additional details regarding DEF's compliance strategies in response to the MATS rule are provided in DEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 140007-EI.

DEF continues to look ahead to the projected retirements of several of the older units in the fleet, particularly combustion turbines at Higgins, Avon Park, Turner and Rio Pinar as well as the three steam units at Suwannee. Turner Unit P3 is projected to retire at the end of 2014. The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. There are many factors which may impact these retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2014 through 2023. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan. Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with DEF Bulk Electric System (BES) are shown in Schedule 10.

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TABLE 3.1

DUKE ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2013

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Fossil Steam			
Crystal River	4	2,291	
Anclote	2	974	
Suwannee River	3	128	
Total Fossil Steam	9	3,393	
Combined Cycle			
Bartow	1	1,160	
Hines Energy Complex	4	1,912	
Tiger Bay	1	205	
Total Combined cycle	6	3,277	
Combustion Turbine			
DeBary	10	637	
Intercession City	14	986	*(1)*
Bayboro	4	174	
Bartow	4	177	
Suwannee	3	155	
Turner	4	131	
Higgins	4	105	
Avon Park	2	48	
University of Florida	1	46	
Rio Pinar	1	12	
Total Combustion Turbine	47	2,471	
Total Units	**62**		
Total Net Generating Capability		**9,141**	

(1) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Firm Qualifying Facility Contracts	11	590	
Investor Owned Utilities	2	413	
Independent Power Producers	2	1,114	
TOTAL CAPACITY RESOURCES		**11,258**	

TABLE 3.2

DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS

AS OF DECEMBER 31, 2013

Facility Name	Firm Capacity (MW)
El Dorado*	114.2
Lake County Resource Recovery **	12.8
LFC Jefferson*	8.5
LFC Madison*	8.5
Mulberry	115
Orange Cogen (CFR-Biogen)	74
Orlando Cogen ***	79.2
Pasco County Resource Recovery	23
Pinellas County Resource Recovery 1	40
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Florida Power Development	60
TOTAL	**589.6**

* El Dorado, LFC Jefferson and LFC Madison expire 12/31/13.

** Lake County Resource Recovery expires 6/1/2014

*** Orlando Cogen increases contract capacity by 35.8MW to 115MW on 1/1/2014

DUKE ENERGY FLORIDA

SCHEDULE 7.1
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL[a] INSTALLED CAPACITY	FIRM[b] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[c]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2014	9,015	1,831	0	177	11,024	8,812	2,211	25%	0	2,211	25%
2015	8,982	1,831	0	177	10,991	9,042	1,949	22%	0	1,949	22%
2016	9,089	1,873	0	177	11,140	9,149	1,991	22%	0	1,991	22%
2017	9,254	1,873	0	177	11,305	9,307	1,998	21%	0	1,998	21%
2018	9,206	1,923	0	177	11,307	9,439	1,868	20%	0	1,868	20%
2019	10,026	1,873	0	177	12,077	9,813	2,264	23%	0	2,264	23%
2020	9,921	1,873	0	177	11,972	9,935	2,037	21%	0	2,037	21%
2021	10,714	1,448	0	177	12,340	9,952	2,388	24%	0	2,388	24%
2022	10,714	1,448	0	177	12,340	10,067	2,273	23%	0	2,273	23%
2023	10,714	1,448	0	177	12,340	10,173	2,167	21%	0	2,167	21%

Notes:

a. Total Installed Capacity does not include the 143 MW to Southern Company from Intercession City, P11.

b. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

c. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 7.2
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2013/14	10,109	1,916	0	190	12,215	8,870	3,345	38%	0	3,345	38%
2014/15	10,062	1,916	0	177	12,155	9,133	3,022	33%	0	3,022	33%
2015/16	10,062	1,946	0	177	12,185	9,370	2,815	30%	0	2,815	30%
2016/17	10,194	1,958	0	177	12,330	9,298	3,032	33%	0	3,032	33%
2017/18	10,194	1,958	0	177	12,330	9,544	2,786	29%	0	2,786	29%
2018/19	11,142	1,958	0	177	13,278	9,639	3,639	38%	0	3,639	38%
2019/20	11,142	1,958	0	177	13,278	9,971	3,306	33%	0	3,306	33%
2020/21	11,026	1,958	0	177	13,162	10,059	3,103	31%	0	3,103	31%
2021/22	11,892	1,533	0	177	13,603	10,144	3,459	34%	0	3,459	34%
2022/23	11,892	1,533	0	177	13,603	10,225	3,378	33%	0	3,378	33%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2014 THROUGH DECEMBER 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY[a]			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
ANCLOTE	1	PASCO	ST	NG		PL			5/2014			17	11	FC/A	(1) and (2)
ANCLOTE	2	PASCO	ST	NG		PL			12/2014			20	19	FC/A	(1) and (2)
TURNER	3	VOLUSIA	GT							12/2014		(53)	(77)	RT	(2)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		4/2016			(50)	(52)	FC	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		4/2016			(79)	(80)	FC	(2)
TURNER	P 1-2	VOLUSIA	GT							6/2016		(20)	(26)	RT	(2)
AVON PARK	P 1-2	HIGHLANDS	GT							6/2016		(48)	(70)	RT	(2)
RIO PINAR	P1	ORANGE	GT							6/2016		(12)	(15)	RT	(2)
SUWANNEE RIVER	P 4-5	SUWANNEE	GT					12/2014	06/2016			316	375	P	(2) and (3)
HINES	2-4	POLK	CC	NG		PL			3/2017			165	0	RP	(2) and (3)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/1966	4/2018		(320)	(320)	RT	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/1969	4/2018		(420)	(423)	RT	(2)
SUWANNEE RIVER	1-3	SUWANNEE	ST							6/2018		(129)	(131)	RT	(2)
CITRUS	1	CITRUS	CC					11/2015	05/2018			1640	1820	P	(2), (3), and (4)
HIGGINS	P 1-4	PINELLAS	GT							6/2020		(105)	(116)	RT	(2)
UNKNOWN	1	UNKNOWN	CC					01/2018	06/2021			793	866	P	(2)

a. See page v. for Code Legend of Future Generating Unit Status.
b. NOTES
(1) Capability was reduced after gas conversion due to FD fan limitations. FD Fan replacement increases the capability to what it was before the Gas Conversion.
(2) Planned, Prospective, or Committed project.
(3) DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews.
(4) Approximately 50% of plant capacity is planned in service 5/2018 with the balance in service 11/2018.

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:	**Suwannee CTs (Units 4 and 5)**	
(2)	Capacity		
	a. Summer:	316	
	b. Winter:	375	
(3)	Technology Type:	COMBUSTION TURBINE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2014	
	b. Commercial in-service date:	6/2016	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	Dry Low NOx Combustion	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	N/A	ACRES
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	3.85	%
	b. Forced Outage Factor (FOF):	2.05	%
	c. Equivalent Availability Factor (EAF):	94.18	%
	d. Resulting Capacity Factor (%):	9.3	%
	e. Average Net Operating Heat Rate (ANOHR):	10,197	BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	35	
	b. Total Installed Cost (In-service year $/kW):	661.57	
	c. Direct Construction Cost ($/kW): ($2014)	605.36	
	d. AFUDC Amount ($/kW):	45.97	
	e. Escalation ($/kW):	10.23	
	f. Fixed O&M ($/kW-yr): ($2014)	3.86	
	g. Variable O&M ($/MWh): ($2014)	3.26	
	h. K Factor:	NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:	**Citrus Combined Cycle**
(2)	Capacity	
	a. Summer:	1640
	b. Winter:	1820
(3)	Technology Type:	COMBINED CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	11/2015
	b. Commercial in-service date:	5/2018 - 11/2018 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	N/A
(6)	Air Pollution Control Strategy:	SCR and CO Catalyst
(7)	Cooling Method:	Cooling Tower
(8)	Total Site Area:	410 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	8.00 %
	b. Forced Outage Factor (FOF):	2.00 %
	c. Equivalent Availability Factor (EAF):	90.16 %
	d. Resulting Capacity Factor (%):	76.6 %
	e. Average Net Operating Heat Rate (ANOHR):	6,624 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	35
	b. Total Installed Cost (In-service year $/kW):	924.19
	c. Direct Construction Cost ($/kW): ($2014)	774.74
	d. AFUDC Amount ($/kW):	99.90
	e. Escalation ($/kW):	49.55
	f. Fixed O&M ($/kW-yr): ($2014)	6.15
	g. Variable O&M ($/MWh): ($2014)	2.03
	h. K Factor:	NO CALCULATION

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:	**Undesignated CC**	
(2)	Capacity		
	a. Summer:	793	
	b. Winter:	866	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	1/2018	
	b. Commercial in-service date:	6/2021	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	SCR and CO Catalyst	
(7)	Cooling Method:	Cooling Tower	
(8)	Total Site Area:	UNKNOWN	ACRES
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.66	%
	b. Forced Outage Factor (FOF):	6.36	%
	c. Equivalent Availability Factor (EAF):	87.40	%
	d. Resulting Capacity Factor (%):	75.6	%
	e. Average Net Operating Heat Rate (ANOHR):	6,741	BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	35	
	b. Total Installed Cost (In-service year $/kW):	1,613.11	
	c. Direct Construction Cost ($/kW): ($2014)	1,281.90	
	d. AFUDC Amount ($/kW):	146.84	
	e. Escalation ($/kW):	184.37	
	f. Fixed O&M ($/kW-yr): ($2014)	6.60	
	g. Variable O&M ($/MWh): ($2014)	5.45	
	h. K Factor:	NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

DEF does not anticipate having any Directly Associated Lines with the designated units in Schedule 8

INTEGRATED RESOURCE PLANNING OVERVIEW

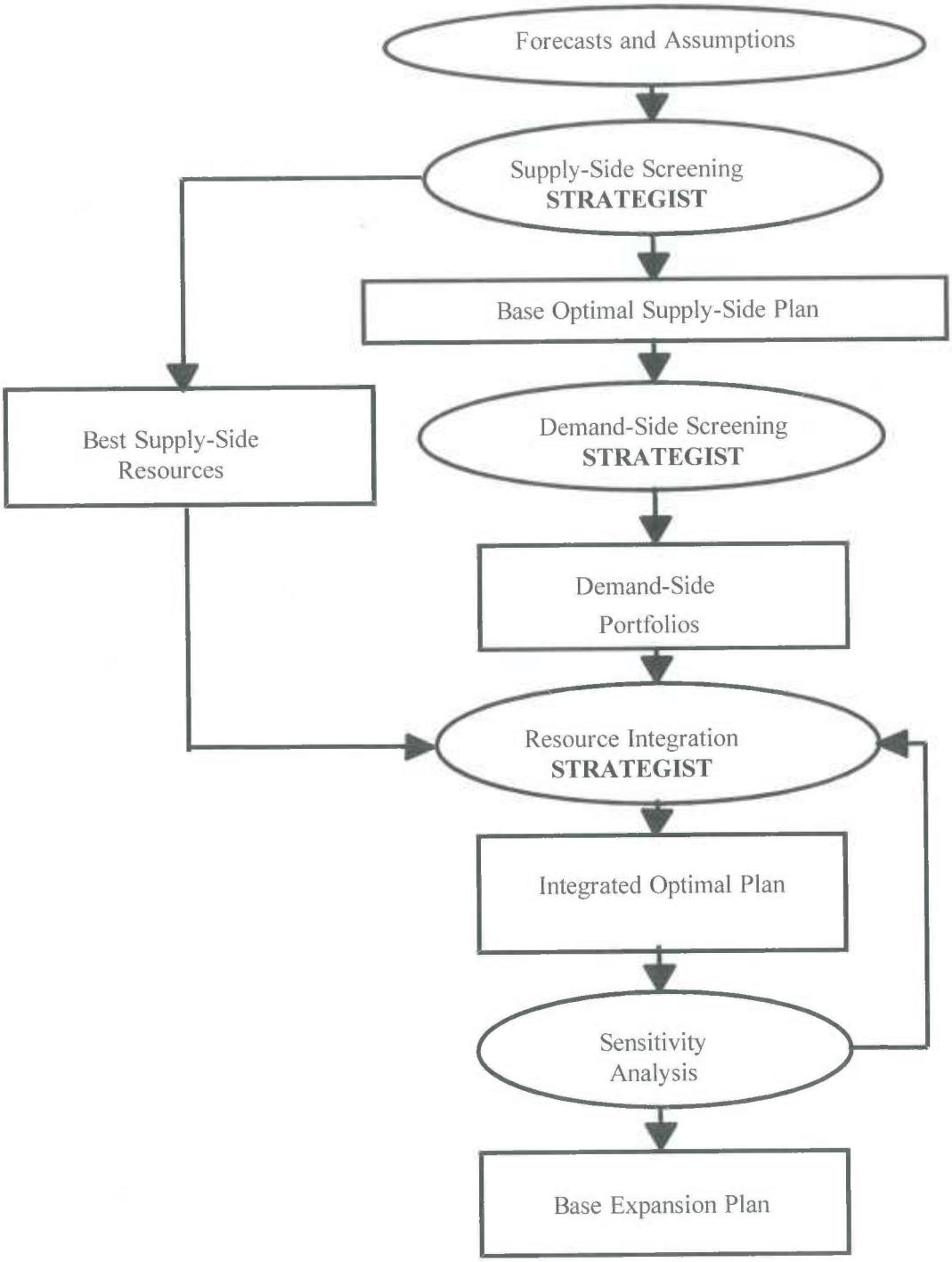
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of DEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for DEF to pursue over the next ten years to meet the Company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides DEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect DEF's view of the most likely future scenario are developed. Additional future scenarios along with high and low forecasts may also be developed. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for DEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

DEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF plans its resources to satisfy a 20 percent Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility

industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

DEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. DEF's resource portfolio is designed to satisfy the 20 percent Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20 percent Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and DEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters (e.g. possible climate legislation), and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the Strategist® optimization program. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements.

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources are also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (e.g. building code), or not applicable to DEF's customers. Strategist® is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. Strategist® calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test.

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the Company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and reasonable revenue requirements (rates) for DEF's ratepayers.

Developing the Base Expansion Plan

The integrated optimized plan that provides the lowest revenue requirements may then be further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it would then be considered the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP.

Fuel Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing

contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in DEF's most recent planning studies were 50 percent debt and 50 percent equity capital structure, projected cost of debt of 3.75 percent, and an equity return of 10.5 percent. The assumptions resulted on a weighted average cost of capital of 7.13 percent and an after-tax discount rate of 6.46 percent.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site.

DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan.

DEF continues to look ahead to the projected retirements of several of the older units in the fleet, particularly combustion turbines at Higgins, Avon Park, Turner and Rio Pinar as well as the three steam units at Suwannee. Turner Unit P3 is projected to retire at the end of 2014.The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. There are many factors which may impact these

retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs.

Through its ongoing planning process, DEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

DEF continues to make purchases from the following facilities listed by fuel type:

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 MW)

Pasco County Resource Recovery (23 MW)

Pinellas County Resource Recovery (54.8 MW)

Waste Heat from Exothermic Processes:

PCS Phosphate (As Available)

Waste Wood, Tires, and Landfill Gas:

Ridge Generating Station (39.6 MW)

Photovoltaics

DEF owned installations (approximately 930 kW)

DEF's Net Metering Tariff includes over 12.5 MW of solar PV

In addition, DEF has contracts with U.S. EcoGen (60 MW) and Florida Power Development (60 MW). U.S. Ecogen will utilize an energy crop, while the Florida Power Development facility utilizes wood products as its fuel source.

DEF has also signed several As-Available contracts utilizing biomass and solar PV technologies.

A summary of renewable energy resources is below.

Supplier	Size (MW)	Currently Delivering?	Anticipated In-Service Date
Lake County Resource Recovery	12.8	Yes	
Pasco County Resource Recovery	23	Yes	
Pinellas County Resource Recovery	54.8	Yes	
Ridge Generating Station	39.6	Yes	
PCS Phosphate	As Avail	Yes	
Florida Power Development, LLC	60	Yes	
U.S. EcoGen Polk	60	No	1/1/17
DEF owned Photovoltaics	1	Yes	
Net Metered Customers (1,118)	12.5	Yes	
Blue Chip Energy - Sorrento	As Avail	No	See Note Below
National Solar - Gadsden	As Avail	No	See Note Below
National Solar - Hardee	As Avail	No	See Note Below
National Solar - Highlands	As Avail	No	See Note Below
National Solar - Osceola	As Avail	No	See Note Below
National Solar - Suwannee	As Avail	No	See Note Below

Note: As Available purchases are made on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required.

DEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. DEF continues to keep an open Request for Renewables (RFR) soliciting proposals for renewable energy projects. DEF's open RFR continues to receive interest and to date has logged over 315 responses. DEF will continue to submit renewable contracts in compliance with FPSC rules.

Depending upon the mix of generators operating at any given time, the purchase of renewable energy may reduce DEF's use of fossil fuels. Non-intermittent renewable energy sources also defer or eliminate the need to construct more conventional generators.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize.

TRANSMISSION PLANNING

DEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing, and to assure the system meets DEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. DEF normally runs this analysis for system peak and off-peak load levels for possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, transmission lines, or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the DEF reliability criteria, some remedial actions are allowed to reduce system loadings; in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it

would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

DEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID_Posted_Rev2.docx.
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_3.docx

DEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev2.docx

DEF proposed bulk transmission line additions are summarized in the following Table 3.3. DEF has listed only the larger transmission projects. These projects may change depending upon the outcome of DEF's final corridor and specific route selection process.

TABLE 3.3
DUKE ENERGY FLORIDA
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2014 – 2023

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1000	DEF	DEBARY	ORANGE CITY	6	11/30/2015	230

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

DUKE ENERGY. FLORIDA

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

DEF's 2014 TYSP Preferred Sites include Citrus County for Combined Cycle natural gas generation (and adjacent to the DEF Crystal River Site) and Suwannee County for Simple Cycle natural gas generation. DEF's expansion plan beyond this TYSP planning horizon includes potential nuclear power at the Levy County greenfield. The Citrus County, Suwannee County and Levy County Preferred Sites are discussed below.

SUWANNEE COUNTY

DEF has identified the existing Suwannee River Energy Center site in Suwannee County for simple cycle CTs (see Figure 4.1.a below). The proposed power block includes two (2) dual fuel CTs using F-class technology. The project area totals approximately 68 acres and is located west of River Road, south of U.S. 90. The project area consists of a naturally occurring pine-oak community of the subject parcel and has a canopy primarily composed of longleaf and slash pine as well as turkey and laurel oak. There are no wetlands within the limits of the project area.

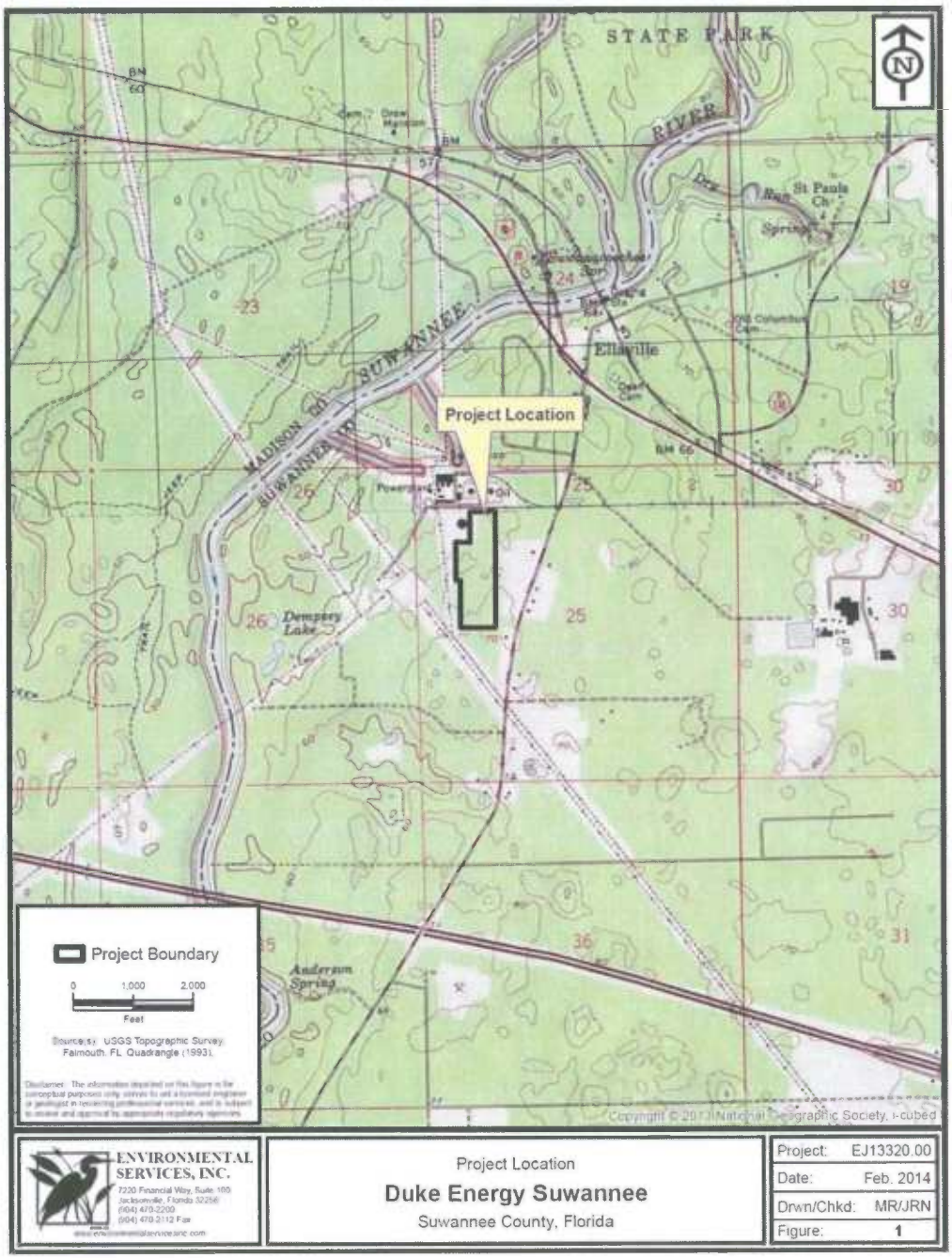
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. DEF will acquire a permit from the Florida Fish and Wildlife Conservation Commission to relocate any gopher tortoises from the project area prior to construction. No archaeological or cultural resources will be adversely impacted by the project.

The new project will not require an increase of water use beyond what is already permitted to be used by the site from the Suwannee River Water Management District. Development of the project site will also require an Environmental Resource Permit and Air Permit from the Florida

Department of Environmental Protection. Suwannee County requires a special exception approval to construct the project on the property.

FIGURE 4.1.a

Suwanee County Preferred Site Location



CITRUS COUNTY

DEF has identified a site in Citrus County as a preferred site for new combined cycle generation (see Figure 4.1.b below). The Company is planning for the construction of a new combined cycle facility on the property with the unit coming on line during 2018. The Citrus site consists of approximately 400 acres of property located immediately north of the Crystal River Energy Center (CREC) transmission line right-of-way and east of the Crystal River Units 4 and 5 coal ash storage area and north of the DEF Crystal River to Central Florida 500-/230-kV transmission line right-of-way. The property consists of regenerating timber lands, forested wetlands, and rangeland bounded to the south by the CREC North Access Road. The site is currently part of the Holcim mine. A new natural gas pipeline will be brought to the Project Site by the natural gas supplier on right of way provided by the supplier. The water pipelines and transmission lines will use existing DEF rights-of-way. No new rail spur is proposed and site access will be via existing roadways.

DEF's assessment of the Citrus site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. No significant issues were identified in DEF's evaluations of the property. The site will be certified by the State of Florida under the Power Plant Siting Act. Federal permits for the development of the site will include a National Pollution Discharge Elimination System (NPDES) permit, Title V Air Operating Permit and a Clean Water Act Section 404 Permit. The site will require Land Use Approval from Citrus County. The new project is proposing to use the existing CR3 intake structure and a new discharge structure in the existing discharge canal.

FIGURE 4.1.b

Citrus County Preferred Site Location

LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

Although the proposed Levy Nuclear Project is no longer an option for meeting energy needs within the originally scheduled time frame, Duke Energy Florida continues to regard the Levy site as a viable option for future nuclear generation and understands the importance of fuel diversity in creating a sustainable energy future. Because of this the Company will continue to pursue the combined operating license outside of the Nuclear Cost Recovery Clause with shareholder dollars as set forth in the 2013 Settlement Agreement. The Company will make a final decision on new nuclear generation in Florida in the future based on, among other factors, energy needs, project costs, carbon regulation, natural gas prices, existing or future legislative provisions for cost recovery, and the requirements of the NRC's combined operating license.

The Levy County site is shown in Figures 4.1.c below:

FIGURE 4.1.c

Levy County Nuclear Power Plant (Levy County)

DEF's Near Term Summer and Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,170	8,812	39,801
2015	9,133	9,042	40,490
2016	9,370	9,149	41,098
2017	9,298	9,307	41,375

DEF's Forecast of Summer Peak Demands and Reserves With and Without Additional Generation Capacity in the Summers of 2016 and 2017

		Including Suwannee CTs and Hines Inlet Chillers		Excluding Suwannee CTs and Hines Inlet Chillers	
Year	Summer Firm Peak Demand	Summer Installed Capacity	Summer Reserve Margin (%)	Summer Installed Capacity	Summer Reserve Margin (%)
2014	8,812	11,024	25.1%	11,024	25.1%
2015	9,042	10,991	21.6%	10,991	21.6%
2016	9,149	11,012	20.4%	10,696	16.9%
2017	9,307	11,232	20.7%	10,696	14.9%

DEF's Forecast Of Physical And Dispatchable Demand-Side Resource Reserves Through the Summers of 2016 And 2017

Year	Summer				
	Peak Demand Before DR	Dispatchable Demand Side Resources	Net Firm Demand	Total Installed Capacity	Reserve Margin
2014	9,641	829	8,812	11,024	25.1%
2015	9,882	840	9,042	10,991	21.5%
2016	9,997	848	9,149	11,012	20.4%
2017	10,196	889	9,307	11,232	20.7%

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GENERATION OPTIONS EVALUATED TO CONTRIBUTE TO DEF'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

New Simple Cycle Units: Suwannee River Plant preferred location (*Selected*)

Thermal Power Uprates: Update compressor, turbine and controls components in the combustion turbines to current design and firing temperatures.

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's
- Hines PB2 Combined Cycle – 2 CT's
- Hines PB3 Combined Cycle – 2 CT's
- Hines PB4 Combined Cycle – 2 CT's

Inlet Chilling: Install electric driven chillers and thermal storage systems to cool inlet air to the combustion turbines during the warm summer months

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's (*Selected*)
- Hines PB2 Combined Cycle – 2 CT's (*Selected*)
- Hines PB3 Combined Cycle – 2 CT's (*Selected*)
- Hines PB4 Combined Cycle – 2 CT's (*Selected*)

Other operations-focused options evaluated and implemented at the Bartow 4 Combined Cycle Plant:

- Replace the steam turbine LP L-0 row turbine blades at the with the OEM's current design

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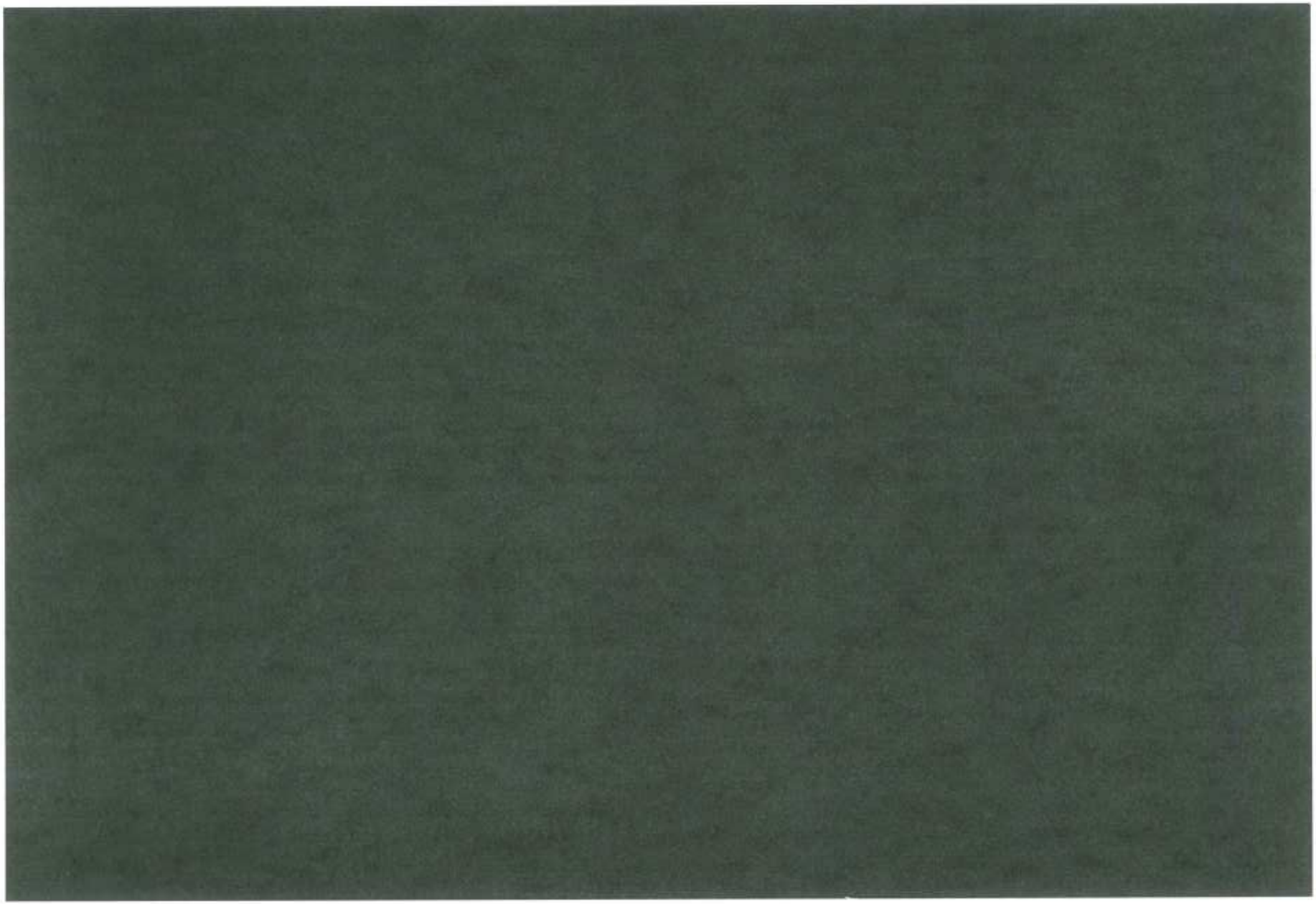

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INITIAL DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build									
$M 2013	PPA 1	PPA 2	PPA 3	Acquisition 2	Acquistion 1	Acquisition - PPA Mix 1	Acquisition - PPA Mix 2	Acquistion 3	Acquistion 4
Capital Costs	37	90	90	(49)	204	101	101	23	(35)
Fuel	395	141	45	(50)	16	(12)	260	7	(3)
Emissions	19	23	19	(71)	(47)	(3)	15	13	1
Variable Costs	19	(4)	(9)	113	34	(4)	10	(0)	1
Fixed Costs	(36)	(122)	(122)	(148)	(162)	(129)	(129)	(310)	(351)
PPAs	(567)	(270)	(184)	44	10	(65)	(375)	9	2
Cogens	(1)	5	6	(36)	(9)	0	(2)	0	1
Emergency Energy	4	2	0	4	2	2	2	3	(2)
Total	(129)	(136)	(155)	(193)	49	(110)	(118)	(255)	(386)

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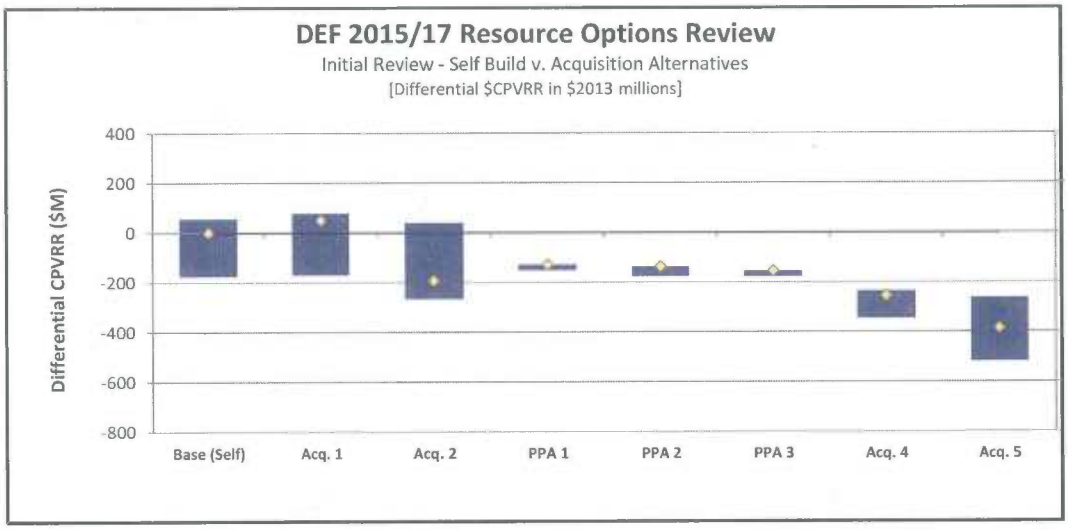
COMPANY'S COST SENSITIVITY ANALYSIS RESULTS BASED ON THE INITIAL DETAILED ECONOMIC ANALYSIS



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

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build				
$M 2014	Acquisition - PPA Mix 1	PPA 1	Self Build No Hines Chillers	Self Build plus Hines 1 Chillers
Capital Costs	88	83	52	(33)
Fuel	50	227	(36)	68
Emissions	16	29	(24)	19
Variable Costs	(9)	2	13	(2)
Fixed Costs	(141)	(129)	(7)	5
PPAs	(143)	(332)	(27)	(29)
Cogens	1	3	(0)	(2)
Emergency Energy	(1)	(1)	3	1
Total	(139)	(118)	(26)	26

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

High Gas Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	35	267	53
Emissions	15	29	21
Variable Costs	(10)	2	(4)
Fixed Costs	(141)	(129)	5
PPAs	(123)	(364)	(1)
Cogens	1	3	(1)
Emergency Energy	(1)	(1)	1
Total	(138)	(110)	41

No CO2 Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	23	205	46
Emissions	(13)	(12)	(1)
Variable Costs	(9)	3	(2)
Fixed Costs	(141)	(129)	5
PPAs	(117)	(311)	(2)
Cogens	(0)	1	(1)
Emergency Energy	(1)	(1)	1
Total	(170)	(161)	14

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. _____
Submitted for filing:
May 27, 2014

DIRECT TESTIMONY OF JULIE SOLOMON

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

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

BY DUKE ENERGY FLORIDA, INC.
FPSC DOCKET NO. _____

DIRECT TESTIMONY OF JULIE SOLOMON

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Julie Solomon. I am employed by Navigant Consulting, Inc. ("Navigant"). My business address is 1200 19th Street, NW, Washington, DC 20036.

Q. What is your job with Navigant Consulting, Inc.?

A. I am a Managing Director in Navigant's Energy Practice. My consulting practice primarily focuses on regulatory issues involving mergers, asset transactions, and market based rate matters, mostly in the context of Federal Energy Regulatory Commission ("FERC") proceedings. I frequently file testimony in this regard.

Q. Please summarize your educational background and employment experience.

A. I have a bachelor's degree in Economics from Connecticut College, and a Masters in Business Administration from the Wharton School of the University of Pennsylvania. Since 1986, I have worked for firms involved in consulting in regulatory and economics matters within the energy industry, and joined Navigant in 2010. I have been involved as either an expert witness or consultant on many of the mergers and acquisitions that

have occurred in recent years. Among these, I was a consultant to Duke Energy in connection with the merger of Duke Energy and Progress Energy. I submitted testimony to FERC on more than 30 mergers or asset purchases since 2010. I also often analyze potential transactions prior to entities entering into a purchase and sale agreement. A copy of my curriculum vitae is attached as Exhibit No. ___ (JS-1) to my direct testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of Duke Energy Florida, Inc. ("DEF" or the "Company"), to explain the results of an analysis that I performed in connection with the Company's evaluation of the most cost-effective generation alternative to meet the Company's capacity need prior to 2018. I was retained by the Company to perform the FERC Competitive Analysis Screen for potential generation facility acquisitions that the Company was considering as part of its evaluation. The Competitive Analysis Screen is also referred to as a Delivered Price Test ("DPT") or an Appendix A analysis (referring to Appendix A of FERC's Merger Policy Statement).

The Competitive Analysis Screen is part of the FERC framework to evaluate the competitive effects of proposed public utility mergers and public utility acquisitions (or disposals) of generation facilities. FERC authorization is required for all proposed public utility acquisitions of generation facilities under section 203 of the Federal Power Act ("FPA"). The Competitive Analysis Screen is one the elements required by FERC to evaluate potential horizontal market power effects in approving public utility acquisitions of generation facilities. I will explain the results of the Competitive Analysis Screen.

The testimony that I provide addresses the FERC framework and, in particular, the Competitive Analysis Screen, and seeks to be helpful to the Florida Public Service Commission ("FPSC" or the "Commission") to understand this framework, the Competitive Analysis Screen, and the results of this analysis of the potential public utility acquisitions of generation facilities.

Q. Are you sponsoring any exhibits to your testimony?

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

- Exhibit No. ___ (JS-1), a copy of my curriculum vitae;
- Exhibit No. ___ (JS-2), a schematic showing DEF's Balancing Authority Area ("BAA") and other BAAs in the Florida Reliability Coordinating Council ("FRCC");
- Exhibit No. ___ (JS-3), sample Herfindahl-Hirschman Index ("HHI") calculations of market concentration;
- Exhibit No. ___ (JS-4), a table depicting the metrics FERC uses to define market concentration and acceptable levels of HHI changes under the Competitive Analysis Screen;
- Exhibit No. ___ (JS-5), a table of the ten periods that are evaluated in the Competitive Analysis Screen;
- Exhibit No. ___ (JS-6), a table of the "Available Economic Capacity ("AEC") calculations derived for DEF in the Competitive Analysis Screen evaluation;
- Exhibit No. ___ (JS-7), a table of the AEC calculations derived for DEF with a ten percent increase in the market price;

- Exhibit No. ___ (JS-8), a table summarizing the differences between the AEC for DEF from Exhibit No. ___ (JS-6) and Exhibit No. ___ (JS-7);
- Exhibit No. ___ (JS-9), results of the Competitive Analysis Screen for potential Acquisition 1;
- Exhibit No. ___ (JS-10), results of the Competitive Analysis Screen for potential Acquisition 2;
- Exhibit No. ___ (JS-11), results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 1; and
- Exhibit No. ___ (JS-12), results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 2.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. The Company cannot acquire either potential Acquisition 1 or potential Acquisition 2 without FERC approval. A necessary step in obtaining FERC approval is the FERC Competitive Analysis Screen, which is the analytical tool FERC requires to evaluate the competitive effects of potential plant acquisitions. I performed the FERC Competitive Analysis Screen for both potential plant acquisitions. Acquisition 1 and Acquisition 2 failed the FERC Competitive Analysis Screen. FERC-required and additional sensitivities confirmed these Competitive Analysis Screen results. In my opinion, there is a reasonable risk that FERC would not approve either Acquisition 1 or Acquisition 2 without mitigation by the Company to eliminate the Competitive Analysis Screen

failures. The only potential, workable structural mitigation available to the Company is building additional transmission facilities to expand the transmission import capability to increase supply in the market and offset the competitive effect of an acquisition. My calculations show that substantial, additional MegaWatts ("MW") of transmission import capability from 600 MWs to over 1,000 MWs, respectively, are required to eliminate the Competitive Analysis Screen failures for these potential plant acquisitions.

III. OVERVIEW OF FERC ANALYSIS IN COMPANY EVALUATION OF POTENTIAL GENERATION FACILITY ACQUISITIONS.

Q. What were you asked to do?

A. I was asked by the Company to assist it with its evaluation of the potential acquisition of existing generation facilities to meet the Company's near-term, future generation capacity needs. In particular, I was asked to perform an analysis required to obtain FERC approval of such acquisitions should they prove to be the most cost-effective generation capacity alternatives to meet the Company's needs. I was not asked to perform and did not perform any analyses or evaluation to determine if in fact these potential generation facility acquisitions were the most cost-effective generation for the Company and its customers.

Q. Who evaluated the potential generation facility acquisitions to determine if they were the most cost-effective alternative generation option for the Company?

A. The Company conducted that evaluation. My understanding is that Mr. Ben Borsch is providing testimony in this proceeding to explain the Company's evaluation and the results of that evaluation. I understand that potential generation facility acquisitions were

one of the generation options to meet the Company's generation capacity needs in that evaluation. The other options were power purchase agreements ("PPAs") with utility and non-utility generators and self-build Company generation projects.

Q. What generation facility acquisitions did you evaluate?

A. I analyzed the Company's potential acquisition of the Acquisition 1 facility and the Acquisition 2 facility. These were the potential generation facility acquisitions that the Company asked me to evaluate under the FERC Competitive Analysis Screen. Acquisition 1 is a combustion turbine ("CT") facility located in DEF's BAA. Acquisition 2 is a combined cycle ("CC") facility located outside DEF's BAA. I used the ratings from EIA Form 860, see http://www.eia.gov/electricity/data/eia860/, which is the plant ratings source typically used by FERC for Acquisition 1 and Acquisition 2.

Q. What is a balancing authority area?

A. A BAA is a term used by the North American Electric Reliability Corporation ("NERC"), and represents a collection of generation, transmission, and loads within its boundaries. The Balancing Authority operator maintains load-resource balance within this area. The BAA typically roughly follows the boundary of a franchise retail service territory for utilities such as DEF, but it could also include generation that is physically located outside of the service territory that is dynamically scheduled into the BAA. In the context of FERC's Competitive Analysis Screen, a BAA represents the default relevant geographic market for evaluating wholesale market power. FERC requires the Competitive Analysis Screen analysis to examine the effect on competition in the BAA

where the generation is interconnected and, for transmission-owning utilities such as DEF, in any interconnected (i.e., "first-tier") BAA. An excerpt from NERC's "bubble map" of BAAs in the FRCC is graphically illustrated in Exhibit No. ___ (JS-2) to my direct testimony.

Q. What is the FERC Competitive Analysis Screen?

A. The FERC Competitive Analysis Screen is the analytical tool that must be employed in the FERC framework to evaluate the competitive effects of a potential public utility generation facility acquisition. This framework was adopted by FERC to evaluate the competitive effects of potential mergers, but FERC applies the same framework to evaluate the competitive effects of potential public utility acquisitions of generation facilities. Under section 203 of the FPA, FERC authorization is required for acquisitions of generation facilities owned by public utilities.

The Competitive Analysis Screen is used to determine if the generation facility acquisition would significantly increase market concentration. Market concentration is a measure of market structure (how many and the relative size of market participants), and FERC uses market concentration and the change in market concentration as a means to evaluate market power, which is defined as the ability to sustain an increase in the market price through unilateral action or collusion to the detriment of potential customers in the market. Market power can be exercised by withholding generation from the market by taking it out of service, thus, restricting supply and increasing the market price at that time, or by raising market prices through offers at higher prices (such actions are referred to as physical and economic withholding, respectively).

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

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

Q. Why did FERC adopt the Competitive Analysis Screen?

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

The FERC focus in the Competitive Analysis Screen is on the effect of the proposed merger or generation facility acquisition on the wholesale market or wholesale customers in the market. FERC's regulatory authority does not extend to whether the generation facility acquisition, for example, is a cost-effective or "good" deal for the public utility and its retail customers or the owner who is selling the generation facility to the public utility. FERC's concern in approving or disapproving the acquisition is on whether the transaction is in the public interest. The three factors in making such a determination are the impact of a transaction on competition in the wholesale market, the effect on wholesale rates, and the effect on regulation.

Q. How do you use the FERC Competitive Analysis Screen?

A. The FERC Competitive Analysis Screen is a forward-looking analysis because the impact of the proposed generation facility acquisition will occur in the future. Therefore, the Screen analysis is applied to a relatively near-term future year view of the market. Implementation of the FERC Competitive Analysis Screen requires: (i) identification of the relevant products, i.e., capacity, energy, or both for potential customers in the market; (ii) identification of customers in the market who may be affected by the acquisition; (iii) identification of the potential suppliers to each identified customer in the market; and (iv) the analysis of the market concentration using the appropriate HHI thresholds.

Q. What is the Herfindahl-Hirschman Index?

A. The HHI is a widely accepted measure of market concentration. FERC, the United States Department of Justice, and the Federal Trade Commission all use HHI metrics to evaluate

market concentration. Because market concentration is a metric that captures the number of entities and their respective shares of relevant supply in a particular market, the HHI is calculated by squaring the market share of each entity competing in the market and summing the results for all market participants. Exhibit No. ___ (JS-3) to my direct testimony provides a sample HHI calculation that demonstrates how the sum of squares of market shares for the market participants is calculated. The fewer the number of entities in the market and the larger certain entities' market share, the higher the HHI. This effect can be readily seen in Exhibit No. ___ (JS-3) by comparing Market X with one supplier on the left side of the Exhibit, Market Y with 4 equal suppliers in the middle of the Exhibit, and Market Y with the proposed merger of entities "B" and "C" on the right side of the Exhibit.

Based on the HHI, markets are categorized as either "unconcentrated," "moderately concentrated," or "highly concentrated." The magnitude of acceptable changes in the HHI, and the corresponding potential merger or acquisition effect on competition in the market, differs depending on the market concentration. The standards FERC applies in this regard are depicted in the HHI market concentration table included as Exhibit No. ___ (JS-4) to my direct testimony. In Exhibit No. ___ (JS-4) any change in the HHI as a result of the potential generation facility acquisition in an unconcentrated market, for example, is unlikely to have any adverse competitive effects. In a highly concentrated market, however, any change greater than 100 points in the HHI as a result of the proposed acquisition is considered an adverse effect on competition in the market because it likely creates or enhances the acquiring entity's market power.

Q. How concentrated is the DEF BAA?

A. Focusing on the AEC metric, as described below, the DEF BAA falls into the moderately concentrated to highly concentrated ranges, depending on the time period analyzed. This means that the target HHI change is no more than 100 points when the market is moderately concentrated and no more than 50 points when the market is highly concentrated. As explained in the bottom row of Exhibit No. ___ (JS-4), if the HHI change exceeds 100 points in the moderately concentrated market, the potential transaction potentially raises significant competitive concerns. If the market is highly concentrated, a HHI change of more than 50 points also means the potential transaction potentially raises significant competitive concerns, and a HHI change of more than 100 points means the potential transaction is likely to create or enhance market power. Market concentration of such levels is not atypical for vertically integrated public utilities in a non-restructured, state-regulated electricity market.

Q. What do you mean by Available Economic Capacity?

A. FERC's Competitive Analysis Screen considers two metrics, Economic Capacity ("EC") defined as energy that can be delivered into a market at a delivered cost less than 105 percent of the presumed market price; and Available Economic Capacity ("AEC"), defined as EC over and above that required to meet native load and other long-term obligations that meet the delivered price test. That is, AEC = EC – native load. Because AEC (as well as EC) is measured under a range of system conditions, and takes into account generation economics, even if a utility has capacity equal to its peak load plus its planning reserve margin requirement, there may be significant AEC available under some

market conditions. It is well established that in non-restructured markets where vertically-integrated utilities maintain load-serving obligations, AEC is the more relevant measure under the Competitive Analysis Screen. In contrast, in restructured markets, for example, in most of the markets operated by Regional Transmission Organizations ("RTO") or Independent System Operators ("ISO"), EC is the more relevant measure.

Q. How are market prices determined for the AEC calculations?

A. FERC requires that the market prices for the Competitive Analysis Screen be based on data in the Electric Quarterly Reports ("EQRs"), except when analyzing RTO or ISO markets where historical hourly data are reported by the governing entities. EQRs are quarterly, historical wholesale price reports that each utility must file with FERC. Remember, however, that the screen is forward-looking so the expected future market price for energy, not the historical energy market price, must be used. The EQRs, therefore, are the starting point for calculating the forecasted market price.

There are some inherent limitations in prices reported in the EQRs for BAAs such as DEF's BAA. Often transactions are limited, because wholesale sales activity is limited. Until very recently, non-FERC jurisdictional entities were not required to file EQRs, thus, the data excluded transactions by non-FERC-jurisdictional entities, and therefore, most of the data reported in the historical EQRs for the DEF BAA is limited to DEF's sales and any wholesale sales made by FERC-jurisdictional entities. As noted, adjustments to the historical energy prices from the EQRs must be made to move prices from historical to expected future prices, primarily consisting of adjustments to reflect changes in fuel costs. This analysis requires a review of historical and future fuel prices

and related marginal costs. FERC also requires testing the sensitivity of the Competitive Screen Analysis results to higher or lower expected market prices.

Other factors must be considered to test the sensibility of the future energy market price. For example, if one finds that the Competitive Screen Analysis using a specific set of prices leads to capacity factors for generation that are significantly different than historically (e.g., plants are not economic at the market price during seasonal periods when one would expect them to be), then the market prices might need to be adjusted. To illustrate, if the future energy price calculation in a certain time period implies that a CC unit is not dispatched in a peak period, but historically CC units have been dispatched in that time period, an adjustment may need to be made to the estimated market price. Thus, determining future market energy prices for the DPT is not a purely quantitative calculation, and qualitative adjustments may be required to ensure a robust Competitive Analysis Screen.

Q. Has FERC accepted such qualitative considerations in determining market prices in the Competitive Analysis Screen?

A. Yes. Although FERC is very specific about the need to use EQRs as the basis for market prices, in appropriate circumstances, FERC has accepted qualitative adjustments to the prices. One example is a transaction involving the Bluegrass generating facility in Kentucky, where EQR-based prices implied that a CT would be economic in far too many hours (almost 30 percent of the time) when its actual capacity factor was more like 3 percent. In re: Bluegrass Generation Company, L.L.C., Louisville Gas and Electric Co., Kentucky Utilities Co., 139 FERC ¶61,094 (2012). In that example, the qualitative

adjustments to the price "improved" the Competitive Analysis Screen results. Certainly, qualitative adjustments also can lead to more conservative results under the Competitive Analysis Screen.

Q. How are transmission capability and imports reflected in the Competitive Analysis Screen?

A. Transmission capability is another important input into the Competitive Analysis Screen. The Competitive Analysis Screen is a measure of competitive supply in the market, which consists of internal generation as well as external generation that can be imported into the market, taking into account generation economics, transmission costs, and the market price. FERC refers to this transmission import capability as the Simultaneous Import Limit ("SIL").

Q. What happens if a proposed generation facility acquisition fails the Competitive Analysis Screen?

A. As I referenced earlier, if the proposed generation facility acquisition fails the Competitive Analysis Screen, and a party cannot demonstrate other market factors limiting market power concerns -- which have not been identified here -- mitigation must be considered if the public utility wants to pursue FERC approval of the acquisition. FERC has demonstrated a preference for "structural" as opposed to "behavioral" mitigation and, to the extent structural mitigation is required, such mitigation must eliminate the screen failures identified in the Competitive Analysis Screen. Typical types of structural mitigation include the divestiture (sale) of owned or controlled generation or

the addition of transmission (e.g., transmission upgrades, or new transmission that has not already been included in any planning studies). Selling generation reduces market concentration by reducing the selling party's market share. Adding transmission reduces market concentration by increasing the size of the market (i.e., imports, or the SIL).

IV. RESULTS OF FERC COMPETITIVE ANALYSIS SCREEN EVALUATION.

Q. How did you evaluate the Company's proposed generation facility acquisitions?

A. I evaluated these proposed acquisitions using the FERC Competitive Analysis Screen that I have just described. My focus was on the competitive effect of the potential acquisitions on the DEF BAA. Both proposed generation facility acquisitions failed the Competitive Analysis Screen. In my opinion, based on my evaluation, it is unlikely that DEF would pass the FERC Competitive Analysis Screen if DEF tries to acquire the Acquisition 1 plant located in DEF's BAA. Also based on my evaluation, it is even less likely that DEF would pass the FERC Competitive Analysis Screen if DEF tries to acquire the Acquisition 2 plant located outside DEF's BAA and incorporate that plant as a DEF network resource on DEF's system.

Q. How did you develop the data underlying the FERC Competitive Analysis Screen?

A. I started by identifying DEF's generation portfolio, including its own generation and PPAs, and then I identified the seasonal capacity ratings and generated estimates of the marginal costs for each generation resource, relying generally on third-party sources for data drawn from public (e.g., Energy Information Administration) filings or third-party databases (e.g., Ventyx). In identifying the DEF generation resources, generation under

long-term PPAs with DEF were assigned to DEF while third-party generation resources located in the DEF BAA, but under long-term PPAs with other entities outside DEF's BAA, were considered "moved out" of the DEF BAA and assigned to the buyer under the PPA.

Next, I used DEF's peak load forecast and built an hourly-load shape based on historical hourly load data. This information was used to define load conditions in ten time periods identified by FERC. FERC determined in a series of FERC orders and regulations addressing the Competitive Analysis Screen evaluation that these time periods appropriately represented the range of relevant system conditions that must be considered in the Competitive Analysis Screen. See, e.g., In re: Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities, 119 FERC ¶ 61,296, p. 106, n.92 (2007); In re: Analysis of Horizontal Market Power under the Federal Power Act, 138 FERC ¶ 61,109 (2012). Exhibit No. ___ (JS-5) to my direct testimony is a table of the ten time periods.

Market prices are another important input to the Competitive Analysis Screen. As I described above, the EQRs were the starting point for the future market prices. The forward-looking period for the market prices here was 2015, when the acquired generation facilities would be added to DEF's system, if the acquisitions took place.

Finally, I included an estimate for the SIL into DEF's BAA. No new SIL analysis was conducted for the purpose of my analysis. Instead, for purposes of my Competitive Analysis Screen, I started with SIL data for the DEF BAA for a 2008-2009 time period that was accepted by FERC in 2012 in connection with market-based rate proceedings before FERC at that time. (In the analysis of potential Acquisition 2, I assumed the

output was fully importable into the DEF BAA). Along with the SIL data, I made an assumption about how many potential suppliers would receive an allocation of imports into the market. Typically, for a full-blown FERC analysis, both a SIL study and modeling of first-tier supplies would be undertaken. Here, in addition to using previous SIL calculations, I merely estimated a number of potential suppliers that were allocated shares of the SIL. These assumptions, while necessary to complete the inputs for the Competitive Analysis Screen, had no material effect on the results of my evaluation.

Before I actually conducted the Competitive Analysis Screen, I completed an interim analysis that I refer to as the "AEC Facts." This analysis merely extracts some key data from the Competitive Analysis Screen insofar as it reflects DEF's ability to participate in the relevant market. These AEC facts are included in the table in Exhibit No. ___ (JS-6) to my direct testimony. The table in Exhibit No. ___ (JS-6) reflects DEF's total generation, its load, its Economic Capacity, which as you recall is the AEC before native load commitments are removed, and its AEC prior to the generation facility acquisition in all ten time periods.

Q. Why did you use the existing SIL study in your Competitive Analysis Screen evaluation?

A. Absent conducting a new SIL study, this is the best available SIL study information. Conducting a SIL study is a complex, time-consuming undertaking, so while such an analysis would be necessary for any actual filing to obtain FERC approval of a public utility merger or generation facility acquisition, it is not necessary to perform the study, where, as here, one can demonstrate that the results of the Competitive Analysis Screen

do not turn on the specific SIL level. I often use the existing FERC-accepted SIL studies to determine if the proposed merger or acquisition likely can pass the Competitive Analysis Screen before asking a client to develop its own studies. That is the approach that I reasonably took in my Competitive Analysis Screen evaluation of the Company's proposed generation facility acquisitions. As discussed below, I also tested the sensitivity of using different SIL levels.

Q. What conclusions do you draw from the AEC facts in the table in Exhibit No. ___ (JS-6) to your direct testimony?

A. The last row of the table of AEC facts in Exhibit No. ___ (JS-6) shows that, based on these market prices, DEF has AEC in only two of the ten time periods. These are the Winter Super Peak and the Winter Peak. I also examined the underlying data and tested whether the AEC results are "knife edge", that is whether, with slightly higher prices, a significant amount of additional capacity becomes economic. This is evident by looking at market prices 10% higher, as shown in Exhibit No. ___ (JS-7), and by a comparison of the amount of AEC that DEF has between the two sets of market prices, as shown in Exhibit No. ___ (JS-8). With prices 10% higher, DEF has AEC in six, rather than just two, of the ten time periods. DEF's AEC ranges from 452 MW to 3,077 MW. Prices do not have to be 10% higher across the board to see some of this "knife-edge" effect. For example, increasing the Winter Off-Peak price by only $2/MWh results in DEF having 1,164 MW additional AEC in that time period. This sensitivity analysis is important, not simply because FERC requires price sensitivities, but because it provides the means to challenge or "test" the validity of the results using the base EQR prices, i.e. whether the

EQR price results are a reasonable reflection of the market price. More typically, my experience is that the +10% and -10% price sensitivities required by FERC do not yield such different results as I found here. These results suggest that the EQR prices understate expected market prices and lead to the conclusion that the 10% higher price results may more accurately reflect a better "base case."

More AEC available in more time periods increases the opportunity that the DEF AEC will coincide with economic supply from the potential generation facility that is the subject of the potential acquisition. The relevant time periods of overlap will differ for a CT such as the Acquisition 1 plant and a CC such as the Acquisition 2 plant. Where there are overlaps, there is more opportunity for increases in market concentration that the FERC Competitive Analysis Screen seeks to identify.

Q. What were the results of your Competitive Analysis Screen?

A. The results of the Competitive Analysis Screen for potential Acquisition 1 are shown in Exhibit No. ___ (JS-9) to my direct testimony. In the base case, using prices based solely on the EQRs (adjusted to a 2015 price), the Acquisition 1 plant capacity is economic in only three time periods, the two Summer Peak periods and the Winter Super Peak period. This is demonstrated in column five in Exhibit No. ___ (JS-9) where the Acquisition 1 plant has economic supply available in these time periods. Only one of these time periods overlaps a time period when DEF has AEC, that is the Winter Super Peak time period, which can be seen by comparing column three and column five in Exhibit No. ___ (JS-9). The HHI change in the far right hand column in Exhibit No. ___ (JS-9) for this time period is 1,221, in a very highly concentrated market where any HHI change

above 100 points indicates the potential transaction is likely to create or enhance market power. As a result, potential Acquisition 1 does not pass the FERC Competitive Analysis Screen. Further, as I discuss below, the results are similar in the required FERC -10% price sensitivity and significantly worse in the FERC +10% price sensitivity.

Q. What were the results of your Competitive Analysis Screen for potential Acquisition 2?

A. The results of the Competitive Analysis Screen for potential Acquisition 2 are shown in Exhibit No. ___ (JS-10) to my direct testimony. In this base case, again using prices based solely on the EQRs, potential Acquisition 2 plant capacity is economic in all but two of the time periods. This is not a surprising outcome; potential Acquisition 2 is a CC plant, and therefore it is more efficient than the CTs in the Acquisition 1 plant and should have economic capacity in more time periods than the Acquisition 1 plant. The only time periods where potential Acquisition 2 plant capacity is not economic are the Shoulder Off-Peak period and the Winter Off-Peak period. This is depicted in column five in Exhibit No. ___ (JS-10). There are periods of overlap with DEF's AEC, however, only in the Winter Super Peak and Winter Peak time periods. This can be seen by comparing column three and column five in Exhibit No. ___ (JS-10). The HHI changes in the far right hand column in Exhibit No. ___ (JS-10) for these time periods is 540 and 1,357, respectively, again, in a very highly concentrated market where any HHI change above 100 points indicates the potential transaction is likely to create or enhance market power. Thus, potential Acquisition 2 does not pass the FERC Competitive Analysis Screen.

Q. Was this the end of your evaluation?

A. No. FERC also requires that you perform price sensitivities around the base case in the Competitive Analysis Screen. I performed the FERC-required sensitivities at a ten percent decrease and increase in price. The results of these sensitivity analyses for the potential Acquisition 1 are contained in the tables in Exhibit No. ___ (JS-11) to my direct testimony. The 10% sensitivity is typically what I use to meet FERC's requirement that price sensitivities be submitted. Here, however, because the EQR prices proved to be so "knife-edge", as I discussed previously, I believed that the base case prices might be understating DEF's AEC. As a result, I believe that the +10% price increase sensitivity might be closer to a base case and, accordingly, I looked at a +20% price increase sensitivity as well.

As shown in the first table in Exhibit No. ___ (JS-11), at a ten percent increase in price, the DEF AEC increases substantially from two to six time periods with a substantial increase in MWs; the economic time periods for Acquisition 1 plant capacity increase from three to four; and the overlap between DEF AEC and Acquisition 1 plant capacity increases from one to two time periods, at the Summer Super Peak 2 period in addition to the Winter Super Peak. There are now two changes in HHI well above the 100 point change limit. Thus, the screen failures increase with a ten percent increase in price.

The screen failures increase further with a twenty percent increase in price. The second table in Exhibit No. ___ (JS-11) contains the 20 percent price increase sensitivity results for potential Acquisition 1. With this price increase, there is DEF AEC in every time period (see column 3 in the second table). There is now an overlap with DEF AEC

in five time periods. Only one of these overlapping time periods is below the HHI change target of 50 points. The other four overlapping time periods have HHI changes well above the 100 HHI point change limit, as shown in the far right column in the second table in Exhibit No. ___ (JS-11). The result is there are four screen failures. As prices increase, therefore, the screen failures increase.

I also conducted the required FERC reduced price sensitivity analysis, using -10%. The third table in Exhibit No. ___ (JS-11) contains the results of this sensitivity analysis. With a ten percent decrease in price, DEF has AEC in only one time period, the Winter Super Peak, where this is an overlap with economic Acquisition 1 plant capacity and a HHI change well above the HHI change limit of 100 points at 1,363. Even in the price decrease sensitivity analysis potential Acquisition 1 fails the Competitive Analysis Screen.

Q. Did you perform the same price sensitivity analyses for potential Acquisition 2?

A. Yes. The results of the ten percent and twenty percent price increase sensitivity analyses, and the ten percent price decrease sensitivity analysis, for potential Acquisition 2 are contained in the tables in Exhibit No. ___ (JS-12) to my direct testimony. The first table in Exhibit No. __ (JS-12) contains the ten percent price increase sensitivity results; the second table contains the twenty percent price increase sensitivity results; and the third table contains the ten percent price decrease sensitivity results. Starting with the ten percent price increase sensitivity results, the fifth column of the first table shows that potential Acquisition 2 has economic capacity in all ten time periods. The DEF AEC in column three increases from two to six time periods with a ten percent increase in price.

That means there is an overlap of the DEF AEC and the economic potential Acquisition 2 plant capacity in six time periods. The HHI change for all six time periods in the far right column of the first table is well over the HHI 100 point change limit. All six overlapping time periods are screen failures.

The screen failures grow with a further increase in price from ten to twenty percent. In the second table in Exhibit No. ___ (JS-12), with a twenty percent increase in price, there is DEF AEC and potential Acquisition 2 economic plant capacity in all ten time periods. As depicted in the far right column in the second table in Exhibit No. ___ (JS-12), nine of the ten overlapping DEF AEC and potential Acquisition 2 economic capacity time periods are screen failures. All nine screen failure time periods are well over the HHI 100 point change limit.

Now, turning to the ten percent price decrease sensitivity analysis results in the third table, DEF has AEC in only one time period, the Winter Super Peak, and potential Acquisition 2 also has economic capacity in that time period, resulting in a HHI change of 701, as shown in the far right column of the third table. This HHI change exceeds the HHI 100 point change limit and, as a result, this potential transaction also fails the Competitive Analysis Screen even when prices decrease.

The FERC required price sensitivity calculations in the Competitive Analysis Screen further confirm that neither potential Acquisition 1 nor potential Acquisition 2 pass the Competitive Analysis Screen.

Q. Were there any other sensitivities that were performed as part of your evaluation?

A. Yes. I also tested my results using significantly higher SILs. Using higher SILs assumes

that transmission import capability has increased relative to the earlier SIL studies accepted by FERC. Higher SILs, therefore, dilute DEF's market share, makes the market less concentrated (lower total HHI), and reduces the HHI changes resulting from a proposed acquisition transaction. Higher SILs increase the possibility that the potential acquisitions may pass the Competitive Analysis Screen. The results of these significantly higher SIL calculation sensitivities did lower the HHI changes for the potential acquisitions, however, they did not result in a change in the outcome of the base case or price sensitivity Competitive Analysis Screen analyses. Both Acquisition 1 and Acquisition 2 still failed the Competitive Analysis Screen even with the higher SILs.

Q. Why did you perform a sensitivity case with higher SILs?

A. Even though the SIL data and study I used in my base case and price sensitivity Competitive Analysis Screen analyses is the best SIL information for the DEF BAA available at this time, I understand that new SIL data likely will become available later this summer when market-based rate filings are made with FERC for the Southeast Region. The FERC likely will not approve any new SIL studies until sometime next year. Nevertheless, I wanted to perform a sensitivity analysis that considered higher import levels. Even assuming significantly higher SILs, the results are directionally the same. Neither potential generation facility acquisition passed the Competitive Analysis Screen. This additional sensitivity analysis provides further confirmation that the results of my Competitive Analysis Screen for these potential acquisitions are conservative.

Q. In your opinion will potential Acquisition 1 pass the Competitive Analysis Screen at FERC?

A. No. As I have explained above, I conservatively evaluated potential Acquisition 1 under the FERC Competitive Analysis Screen and the acquisition fails the screen. The additional sensitivity analyses that I performed that I have described above confirm this result. In my opinion, there is a reasonable risk that FERC would not approve this generation facility acquisition without mitigation by the Company. These are the kinds of risks I typically evaluate for parties considering asset transactions requiring FERC approval. As a result, there is a risk that FERC would require mitigation.

Q. In your opinion will potential Acquisition 2 pass the Competitive Analysis Screen at FERC?

A. No. As I have also explained above, I conservatively evaluated potential Acquisition 2 under the FERC Competitive Analysis Screen and that acquisition also fails the screen. The additional sensitivity analyses that I performed that I have described above confirm this result too. In my opinion, and for the same reasons discussed above with respect to Acquisition 1, there is a reasonable risk that FERC would not approve this generation facility acquisition without mitigation by the Company.

Q. What mitigation, if any, is available to the Company to mitigate these Competitive Analysis Screen failures?

A. As I explained above, there are two typical structural remedial measures, reducing DEF owned or controlled generation capacity in the market by selling off its generation

facilities or expanding the market by increasing its overall transmission import capability. Selling off generation to alleviate the Competitive Analysis Screen failure makes no sense for DEF because DEF needs additional generation capacity to meet its reliability need. Indeed, that is the reason DEF is considering these acquisitions in the first place, namely that DEF needs additional capacity. The only potential, workable structural mitigation available to DEF to alleviate the Competitive Analysis Screen failures for these potential generation facility acquisitions is increasing the transmission import capability. This means DEF must build additional transmission facilities to expand the transmission import capability (i.e. the SIL).

Q. Were you asked to evaluate potential transmission mitigation for the Competitive Analysis Screen failures?

A. Yes. Once it became clear that both potential generation facility acquisitions failed the FERC Competitive Analysis Screen and additional transmission import capability was the only potential, workable mitigation, the Company asked me to determine what additional transmission import capability would be required to mitigate the screen failures. I used the same FERC-approved SIL study and data that I used in the FERC Competitive Analysis Screen evaluation as well as additional DEF and market generation and transmission information to perform calculations to estimate the additional transmission import capability (SIL) to mitigate the FERC Competitive Analysis Screen failures. In the case of potential Acquisition 1, I estimated, based on my analysis, that approximately 600 MWs to 800 MWs of additional transmission import capability were necessary to mitigate the Competitive Analysis Screen failures. In the case of potential

Acquisition 2, the increase in transmission import MW capability was even higher, with in excess of 1,000 MWs of additional transmission import capability mitigation required. The results of my transmission import capability mitigation analyses were provided to the Company.

It is important to note that increased transmission capability requires an increase in the SIL, not just an increase on any particular transmission line. Because where the transmission limit occurs can differ in each season, increasing transmission across one interface may or may not increase the SIL in each season. This further complicates the determination of how much transmission is needed. In addition, DEF cannot rely on already planned transmission upgrades or improvements to increase the SIL. Such planned upgrades or improvements cannot be considered as mitigation to address the Competitive Analysis Screen failures and, therefore, they cannot be counted as part of the structural remedy by DEF.

Q. In your opinion, are the results of your mitigation evaluations for the Company's potential generation facility acquisitions reasonable?

A. Yes. These results are based on detailed calculations using reasonable data and analyses under these circumstances where there are substantial Competitive Analysis Screen failures under conservative FERC Competitive Analysis Screen base case and sensitivity analyses.

Q. Can FERC waive the requirements to file a Competitive Analysis Screen?

A. No. FERC's regulations contain limited exemptions from filing a Competitive Analysis

Screen under specific circumstances, but such exemptions are not applicable here. The Competitive Analysis Screen need not be filed if the applicant can demonstrate that they do not conduct business in the same geographic market or the extent of business transactions in the same geographic market is *de minimis* (and no intervenor has alleged that the parties are perceived potential competitors in the same geographic market). There is no procedure to seek a waiver of filing an analysis, absent meeting these limited exemptions.

Q. Can FERC simply ignore failures of the Competitive Analysis Screen?

A. No. When there is a screen failure, applicants are required to provide evidence of relevant market conditions that indicate a lack of a competitive problem, which as I explained above are not present here, or propose mitigation. There are limited circumstances in which FERC may determine that screen failures do not lead to a conclusion that there is a competitive concern, but that of course, means FERC has addressed the Competitive Analysis Screen failure results in a proceeding before FERC and reached that conclusion based on the evidence presented in that proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

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Professional History

- Managing Director, Navigant Consulting - 2010-Present
- Vice President, Charles River Associates - 2001-2010
- Senior Vice President, Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC - 1986-2000
- Economist, Economic Consulting Services, Inc., Washington, DC - 1979-1986
- Economist, U.S. Department of Labor, Washington, DC - 1976-1979

Education

- M.B.A. Finance, The Wharton School University of Pennsylvania
- B.A. Economics, Connecticut College

Testimony

- Written testimony provided in more than 150 regulatory proceedings

Julie Solomon is a Managing Director at Navigant Consulting, Inc. in the Energy Practice's Power Systems, Markets & Pricing group. She has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. Ms. Solomon has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. She has filed testimony in numerous proceedings before the Federal Energy Regulatory Commission. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings in the electricity market.

» Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

» Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

» Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

» Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

» Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

» Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

» Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

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Professional Experience

Electric and Gas Utilities

Mergers and Acquisitions (Market Power and Competition Issues)

» Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

» Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

» Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

» Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

» Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

» Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

» Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

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- Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.

- Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.

- Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.

- Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

Business Valuation

- Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.

- Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.

- Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.

- Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

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Testimony or Expert Report Experience

- Affidavit on behalf of NatGen Southeast Power LLC, Docket No. EC14-81, application for authorization of disposition of jurisdictional facilities, April 28, 2014.
- Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Illinois Commerce Commission, Application for a Certificate of Public Convenience and Necessity, No. 13-0657, April 9, 2014.
- Affidavit on behalf of KMC Thermo, LLC, Docket No. ER14-1468, market-based rate application, March 12, 2014.
- Affidavit on behalf of Trailstone Power, LLC, Docket No. ER14-1439, market-based rate application, March 6, 2014.
- Affidavit on behalf of MACH Gen, LLC et al., Docket No. EC14-61, application for authorization of disposition of jurisdictional facilities, March 4, 2014.
- Affidavit on behalf of MidAmerican Geothermal, LLC, et al., Docket No. EC14-59, application for authorization of disposition of jurisdictional facilities, February 20, 2014.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER11-1933, market-based rate triennial filing, February 7, 2014.
- Affidavit on behalf of NorthWestern Corporation, et al., Docket No. EC14-41, application for authorization of disposition of jurisdictional facilities, January 10, 2014.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, notification of change in status, January 10, 2014.
- Affidavit on behalf of MidAmerican Energy, Docket No. ER10-2475, notification of change in status, January 2, 2014.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of TransAlta, Docket No. ER10-2847, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Duquesne Light Company, Docket No. ER10-1910, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Constellation Energy Nuclear Group, Docket No. ER10-2179, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Dominion, Docket No. ER13-434, market-based rate triennial filing, December 30, 2013.

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- Affidavit on behalf of Brookfield Companies, Docket No. ER10-2895, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER14-882, notification of change in status/tariff filing, December 30, 2013.
- Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 26, 2013.
- Affidavit on behalf of JPMorgan, Docket No. ER10-2331, market-based rate triennial filing, December 23, 2013.
- Affidavit on behalf of Northeast Utilities, Docket No. ER10-1801, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Iberdrola, Docket No. ER10-2822, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of PHI, Docket No. ER10-2997, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Essential Power, Docket No. ER12-952, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Empire District, Docket No. ER14-793, notification of change in status/tariff filing, December 20, 2013.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER14-724, notification of change in status/tariff filing, December 19, 2013.
- Affidavit on behalf of Alpha Gen Power, LLC, Docket No. ER14-630, market-based rate application, December 16, 2013.
- Affidavit on behalf of Black Bear Hydro Partners, LLC, Docket No. EC14-28, application for authorization of disposition of jurisdictional facilities, November 14, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, Docket No. ER10-2474, notification of change in status, November 4, 2013.
- Affidavit on behalf of ECP, Docket No. ER11-3859, notification of change in status, September 30, 2013.
- Affidavit on behalf of Steele Flats Wind Project, LLC, Docket No. ER13-2474, market-based rate application, September 27, 2013.
- Affidavit on behalf of Tuscola Wind II, LLC, Docket No. ER13-2458, market-based rate application, September 26, 2013.
- Affidavit on behalf of Pheasant Run Wind, LLC and Pheasant Run Wind II, LLC, Docket Nos. ER13-2461-2, market-based rate applications, September 26, 2013.

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- Affidavit on behalf of TPF II and USPG Holdings, LLC, Docket No. EC13-154, application for authorization of disposition of jurisdictional facilities, September 25, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket Nos. ER13-2316-9, market-based rate applications, September 4, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket No. EC13-143, application for authorization of disposition of jurisdictional facilities, September 4, 2013.
- Supplemental Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, August 17, 2013.
- Affidavit on behalf of Desert Sunlight 250, LLC and Desert Sunlight 300, LLC, Docket Nos. ER13-1991-2, market-based rate applications, July 17, 2013.
- Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, July 12, 2013.
- Affidavit on behalf of Calpine Southwest MBR Sellers, Docket No. ER10-1942, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1847, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Wayzata Entities, Docket No. ER10-1777, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3415, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, *et al.* under ER10-2474, Docket No. ER10-24744, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of SGOC Southwest MBR Sellers, Docket No. ER10-2864, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of GWF Energy LLC, et al. Docket No. ER10-3301, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of NV Energy, Inc., application for approval of internal reorganization, Docket No. EC13-113, May 31, 2013.
- Affidavit on behalf of Midwest Generation, LLC, Docket No. EC13-103, application for authorization of disposition of jurisdictional facilities, May 6, 2013.
- Affidavit of behalf of Nevada Power Company (with Matthew E. Arenchild), Docket No. EC13-96, application for authorization of disposition of jurisdictional facilities, April 17, 2013.

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- Affidavit of behalf of Dynegy Inc., Docket No. EC13-93, application for authorization of disposition of jurisdictional facilities, April 16, 2013.
- Application on behalf of Florida Power & Light Company, Docket No. EC13-91, application for authorization of disposition of jurisdictional facilities, April 12, 2013.
- Affidavit on behalf of Blythe Energy LLC, et al., Docket No. EC13-89, application for authorization of disposition of jurisdictional facilities, April 2, 2013.
- Affidavit on behalf of New Harquahala Generating Company, LLC, Docket No. ER10-3310, market-based rate triennial filing, March 29, 2013.
- Affidavit on behalf of Dominion Energy Brayton Point, et al., Docket No. EC13-82, application for authorization of disposition of jurisdictional facilities, March 21, 2013.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, January 29, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. ER13-773, market-based rate application, January 17, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. EC13-63, application for authorization of disposition of jurisdictional facilities, January 16, 2013.
- Affidavit on behalf of Calpine Oneta Power, LLC, Docket No. ER11-3777, et al., market-based rate triennial filing, December 31, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER12-569, et al., market-based rate triennial filing, December 27, 2012.
- Affidavit on behalf of Nevada Power Company, Docket No. ER10-2474, market-based rate triennial filing, December 26, 2012.
- Testimony on behalf of Powerex Corp re Puget Sound Energy, Inc v. All Jurisdictional Sellers of Energy & Capacity, Docket No. EL01-10, December 17, 2012.
- Affidavit on behalf of AES Beaver Valley, LLC, Docket No. ER13-442, market-based rate application, November 21, 2012.
- Affidavit on behalf of Broad River Energy LLC, et al., Docket No. EC13-42, application for authorization of disposition of jurisdictional facilities, November 16, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, notice of change in status, October 29, 2012.
- Affidavit on behalf of Homer City Generation, L.P., Docket No. ER13-55, market-based rate application, October 9, 2012.
- Affidavit on behalf of Homer City Generation, L.P., et al., Docket No. EC13-9, application for authorization of disposition of jurisdictional facilities, October 9, 2012.

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- Affidavit on behalf of GenOn Marsh Landing, LLC, Docket No. ER12-2545, market-based rate application, August 29, 2012.
- Affidavit on behalf of High Mesa Energy, LLC, Docket No. ER12-2528, market-based rate application, August 27, 2012.
- Affidavit on behalf of Brandon Shores LLC, et al., Docket No. EC12-137, application for authorization of disposition of jurisdictional facilities, August 23, 2012.
- Affidavit on behalf of North Sky River Energy, LLC, Docket No. ER12-2444, market-based rate application, August 14, 2012.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, August 1, 2012.
- Affidavit on behalf of Canandaigua Power Partners, LLC et al., Docket No. ER10-2460, notice of change in status, July 16, 2012.
- Affidavit on behalf of Limon Wind I and Limon Wind II, LLC, Docket Nos. ER12-2225 and -2226, market-based rate application, July 10, 2012.
- Affidavit on behalf of Ensign Wind, LLC, Docket No. ER12-2227, market-based rate application, July 10, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1836, et al., market-based rate triennial filing, July 2, 2012.
- Affidavit on behalf of Iberdrola Renewables, LLC, et al., Docket No. ER10-2994, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER10-2563, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER12-2124, market-based rate triennial filing, June 28, 2012.
- Affidavit on behalf of Duke Energy Beckjord, LLC, et al., Docket No. ER12-1946 et al., market-based rate application, June 5, 2012.
- Affidavit on behalf of Minco Wind III, LLC, Docket No. ER12-1880, market-based rate application, May 31, 2012.
- Affidavit on behalf of Tuscola Bay Wind, LLC, Docket No. ER12-1660, market-based rate application, April 30, 2012.

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- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, notice of change in status, April 13, 2012.
- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, notice of change in status, April 11, 2012.
- Affidavit on behalf of Hot Spring Power Company, LLC, Docket No. EC12-87, application for authorization of disposition of jurisdictional facilities, March 28, 2012.
- Affidavit on behalf of High Majestic Wind II, LLC, Docket No. ER12-1228, market-based rate application, March 8, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc. et al., Docket No. ER10-2034 et al., notice of change in status, January 31, 2012.
- Affidavit on behalf of CPV Cimarron Renewable Energy Company, LLC, Docket No. ER12-775, market-based rate application, January 6, 2012.
- Affidavit on behalf of LS Power Marketing, LLC, et al., Docket No. ER10-2739, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC, et al., Docket No. ER10-1945, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER10-2034, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Northern Indiana Public Service Company, Docket No. ER10-1781, market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC Docket No. ER10-2566, notice of change in status, December 27, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of Exelon Generation Company, LLC, et al., Docket No. ER10-1144, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., notice of change in status, December 23, 2011.
- Affidavit on behalf of Perrin Ranch, LLC, Docket No. ER12-676, market-based rate application, December 22, 2011.
- Affidavit on behalf of GenOn Energy Management, LLC, et al., Docket No. ER10-1869, et al., market-based rate triennial filing, December 16, 2011.

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- Affidavit on behalf of Blackwell Wind, LLC, Docket No. ER12-569, market-based rate application, December 7, 2011.
- Affidavit on behalf of Bluegrass Generation Company, L.L.C. et al., Docket No. EC12-29, application for authorization of disposition of jurisdictional facilities, November 14, 2011.
- Affidavit on behalf of Dynegy Danskammer, L.L.C., et al., Docket No. EC12-27, application for authorization of disposition of jurisdictional facilities, November 8, 2011.
- Affidavit on behalf of LSP Energy Limited Partnership, et al., Docket No. EC12-19, application for authorization of disposition of jurisdictional facilities, November 1, 2011.
- Affidavit on behalf of Tenaska Power Management, LLC, Docket No. ER12-60, market-based rate application, October 11, 2011.
- Testimony on behalf of Florida Power & Light Company, Docket No. ER12-46, October 7, 2011.
- Affidavit on behalf of Montezuma Wind II, LLC and Vasco Winds, LLC, Docket No. ER11-4677 and ER11-4678, market-based rate applications, September 28, 2011.
- Affidavit of Amsterdam Generating Company, LLC, et al. under Docket No. EC11-118, application for authorization of disposition of jurisdictional facilities, September 9, 2011.
- Affidavit on behalf of Minco Wind II, LLC, Docket No. ER11-4428, market-based rate application, September 2, 2011.
- Affidavit on behalf of Osage Wind, LLC, Docket No. ER11-4363, market-based rate application, August 24, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al. and Calvert Cliffs Nuclear Power Plant, LLC, et al. Docket No. ER10-2179, et al. Notice of Change in Status, August 19, 2011.
- Affidavit on behalf of Michigan Wind II, LLC, Docket No. ER11-3989, market-based rate application, August 17, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group, Docket No. EC11-97, application for authorization of disposition of jurisdictional facilities, July 22, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., Supplemental market-based rate filing, July 22, 2011.
- Affidavit on behalf of South Carolina Electric & Gas Co, Docket No. ER10-2498, market-based rate triennial filing, July 14, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER10-2566, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of North Allegheny Wind, LLC, Docket No. ER10-1330, et al.., market-based rate triennial filing, June 30, 2011.

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- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1838, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1852, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3142 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of MATEP Limited Partnership, Docket No. ER10-3194, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group Inc., Docket No. ER94-1384 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Louisville Gas and Electric Company et al., Docket No. ER10-1511 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Progress Companies, Docket No. ER10-1760 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Mojave Solar, LLC, Docket No. ER11-3917, market-based rate application, June 29, 2011.
- Affidavit on behalf of GDF SUEZ Northeast MBR Sellers, Docket No. ER10-2670 et al., market-based rate triennial filing, June 24, 2011.
- Affidavit on behalf of Alcoa Companies, Docket No. ER10-3069 et al., market-based rate triennial filing, June 23, 2011.
- Affidavit on behalf of Northwestern Corporation, Docket No. EC11-88, application for authorization of disposition of jurisdictional facilities, June 6, 2011.
- Testimony, with Joe D. Pace, on behalf of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83, merger application, May 20, 2011.
- Affidavit on behalf of The AES Corporation and DPL Inc., Docket No. EC11-81, application for authorization of disposition of jurisdictional facilities, May 18, 2011.
- Affidavit on behalf of Wildcat Power Holdings, LLC, Docket No. ER11-3336, market-based rate application, April 15, 2011.
- Affidavit on behalf of TPF Generation Holdings, LLC, University Park Energy, LLC, and LSP Park Generating, LLC, Docket No. EC11-61, application for authorization of disposition of jurisdictional facilities, April 4, 2011.
- Affidavit on behalf of Entegra Power Group LLC, Gila River Power, L.P., and Wildcat Power Holdings, LLC, Docket No. EC11-54, application for authorization of disposition of jurisdictional facilities, May 22, 2011.

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- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, market-based rate triennial filing, January 28, 2011.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, January 21, 2011.
- Affidavit on behalf of Mountain View Power Partners IV, LLC, Docket No. ER11-2701, market-based rate application, January 19, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., market-based rate triennial filing, January 3, 2011.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, Docket No. ER05-1232, market-based rate triennial filing, December 31, 2010.
- Affidavit on behalf of the Exelon MBR Companies, Docket No. ER10-1048, et al., market-based rate triennial filing, December 30, 2010.
- Affidavit on behalf of First Wind Energy Marketing, LLC, et al., Docket No. ER09-1549, et al. , market-based rate application, December 30, 2010.
- Affidavit on behalf of the IRI MBR Companies, Docket No. ER11-2462, et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER01-989, market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Baltimore Gas and Electric Company et al., Docket Nos. ER10-2172 et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Dominion Resources Services, Inc., on behalf of Virginia Electric and Power Company and affiliates, Docket No. ER01-468, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER98-2494, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Atlantic City Electric Company et al., Docket No. ER96-1351 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Allegheny Companies, Docket No. ER11-2481 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Red Mesa Wind, LLC, Docket No. ER11-2192, market-based rate application, November 25, 2010.
- Affidavit on behalf of Duke Energy Vermillion II, LLC; Duke Energy Hanging Rock II, LLC; Duke Energy Lee II, LLC; Duke Energy Washington II, LLC; Duke Energy Fayette II, LLC; Docket Nos. ER11- 2063-6 and 2069, market-based rate application, November 10, 2010.

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- Affidavit on behalf of Elk City II Wind, LLC, Docket No. ER11-2037, market-based rate application, November 5, 2010.
- Affidavit on behalf of AES Laurel Mountain, LLC, Docket No. ER11-2036, market-based rate application, November 5, 2010.
- Supplemental Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, October 29, 2010.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, October 18, 2010.
- Supplemental Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, October 8, 2010.
- Affidavit on behalf of Harbor Gen Holdings, LLC, et al., Docket No. EC11-3, application for authorization of disposition of jurisdictional facilities, October 6, 2010.
- Affidavit on behalf of Ashtabula Wind III, LLC, Docket No. ER11-26, market-based rate application, October 5, 2010.
- Affidavit on behalf of LSP Safe Harbor Holdings, LLC, Docket No. ER11-27, market-based rate application, October 5, 2010.
- Affidavit on behalf of Exelon Corporation, et al., Docket No. EC10-105, application for authorization of disposition of jurisdictional facilities, September 30, 2010.
- Supplemental Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, September 23, 2010.
- Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, September 23, 2010.
- Affidavit on behalf of Minco Wind, LLC, Docket No. ER10-2720, market-based rate application, September 17, 2010.
- Affidavit on behalf of Baldwin Wind, LLC, Docket No. ER10-2551, market-based rate application, September 7, 2010.
- Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, August 18, 2010.
- Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, market-based rate application, August 18, 2010.
- Affidavit on behalf of Calpine Mid-Atlantic Marketing, LLC, Docket No. ER10-2029, market-based rate application, July 29, 2010.
- Affidavit on behalf of Sundevil Power Holdings, LLC, Docket No. ER10-1777, market-based rate application, July 14, 2010.

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- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, July 9, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER02-2018 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Mirant, Docket No. ER01-1270 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of CalPeak Entities and Tyr Energy, LLC, Docket No. ER06-1331, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Starwood Power-Midway, Docket No. LLC under ER08-110, triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation and BE CA LLC in ER05-1232, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of AES 2, L.L.C., et al. Docket No. ER99-2284, et al., triennial market-based rate update, June 29, 2010.
- Affidavit on behalf of Sierra Pacific Power Company and Nevada Power Company, Docket No. ER01-1527 et al., triennial market-based rate update, June 28, 2010.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 23, 2010.
- Affidavit on behalf of Mirant Corporation and RRI Energy, Inc., application for authorization to transfer jurisdictional facilities, Docket No. EC10-70, May 14, 2010.
- Affidavit on behalf of New Development Holdings, LLC et al., application for authorization to transfer jurisdictional facilities, Docket No. EC10-64, May 6, 2010.
- Supplemental affidavit on behalf of JPMorgan Chase, Docket No. ER07-1358 et al., notice of change in status regarding market-based rate authorization, April 16, 2010.
- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, April 12, 2010.
- Supplemental affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, April 9, 2010.
- Affidavit on behalf of Big Horn Wind Project LLC and Juniper Canyon Wind Power LLC, Docket Nos. ER10-974 and 975, market-based rate application, March 31, 2010.
- Affidavit on behalf of CER Generation, LLC Docket No. ER10-662, market-based rate application, March 19, 2010.

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- Affidavit on behalf of Calpine Corporation, Docket No. ER00-3562 et al., triennial market-based rate update, March 16, 2010.
- Affidavit on behalf of NV Energy, Docket No. ER01-1529 et al., triennial market-based rate update, March 8, 2010.
- Affidavit on behalf of Day County Wind, LLC, Docket No. ER10-825, market-based rate application, March 4, 2010.
- Affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, March 1, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-149 et al., triennial market-based rate update, March 1, 2010.
- Supplemental affidavit on behalf of The Empire District Company, Docket No. ER99-1757, triennial market-based rate update, February 22, 2010.
- Supplemental affidavit on behalf of Oklahoma Gas and Electric Company & OGE Energy Resources, Inc., Docket No. ER98-511 and ER97-4345, triennial market-based rate update, February 19, 2010.
- Supplemental affidavit on behalf of Westar Energy, Inc., ER98-2157 et al., triennial market-based rate update, February 18, 2010.
- Affidavit on behalf of AES ES Westover, LLC, Docket No. ER10-712, market-based rate application, February 5, 2010.
- Affidavit on behalf of RRI Florida MBR Companies, Docket No ER09-1110 et al. notice of change in status regarding market-based rate authorization, February 1, 2010.
- Affidavit on behalf of Wolverine Power Supply Cooperative, Inc. and FirstEnergy Generation Corp., Docket No. EC10-41, January 21, 2010.
- Affidavit on behalf of FPL Energy Illinois Wind, LLC, Docket No. ER10-402, market-based rate application, December 10, 2009.
- Affidavit on behalf of NextEra Companies, Docket No. ER09-832, et al., notice of change in status regarding market-based rate authorization, December 7, 2009.
- Affidavit on behalf of Garden Wind, LLC, Docket No. ER10-296 and Crystal Lake Wind III, LLC, Docket No. ER10-297, market-based rate application, November 23, 2009.
- Affidavit on behalf of Stateline II, LLC, Docket No. ER10-256, market-based rate application, November 16, 2009.
- Affidavit on behalf of Elk City Wind, LLC, Docket No. ER10-149, market-based rate application, November 2, 2009.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, October 30, 2009.

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- Affidavit on behalf of CPV Keenan II Renewable Energy Co, LLC, Docket No. ER10-64, market-based rate application, October 16, 2009.
- Supplemental Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, October 7, 2009.
- Affidavit on behalf of High Majestic Wind Energy Center, LLC, Butler Ridge Wind Energy Center, LLC, and Wessington Wind Energy Center, LLC, Docket Nos. ER10-1-3, market-based rate applications, October 6, 2009.
- Affidavit on behalf of Powerex Corp. in State of California, ex rel. Lockyer v. British Columbia Power Exchange Corp., et al., Docket No. EL02-71, September 17, 2009.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 14, 2009.
- Affidavit on behalf of Powerex Corp. in State of California, ex rel. Edmund G. Brown, Attorney General for the State of California v. Powerex Corp. (f/k/a British Columbia Power Exchange Corp.), et al., Docket No. EL09-56, September 3, 2009.
- Affidavit on behalf of Ashtabula Wind II, LLC, Docket No. ER09-1656, market-based rate application, September 1, 2009.
- Affidavit on behalf of Oklahoma Gas and Electric Company et al., Docket No. ER98-511 et al., triennial market power update, July 30, 2009.
- Affidavit on behalf of Westar Energy, Inc & Kansas Gas and Electric Company, Docket No. ER98-2157 et al., triennial market power update, July 30, 2009.
- Affidavit on behalf of The Empire District Electric Company, Docket No .ER99-1757, triennial market power update, July 30, 2009.
- Affidavit on behalf of NextEra Companies, Docket No. ER08-1297, et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER00-3562, et al. triennial market power update, June 30, 2009.
- Affidavit on behalf of Dominion Energy Kewaunee, Inc., Docket No. ER04-318, triennial market power update, June 30, 2009.
- Affidavit on behalf of CinCap IV, LLC, Docket No. ER05-1372 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER98-855, triennial market power update, June 30, 2009.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, et al., Docket No. ER05-1232, et al., triennial market power update, June 30, 2009.

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- Affidavit on behalf of Iberdrola Renewables, Inc et al., Docket No. ER08-912 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Exelon Generation Co, LLC et al., Docket No. ER00-3251 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 26, 2009.
- Affidavit on behalf of GenConn Middletown, LLC and GenConn Devon, LLC, Docket Nos. ER09-1300-1301, market-based rate application, June 15, 2009.
- Affidavit on behalf of Northern Colorado Wind Energy, Docket No. ER09-1297, market-based rate application, June 12, 2009.
- Affidavit on behalf of Fox Energy Company LLC, Docket No. ER03-983, triennial market power update, June 3, 2009.
- Affidavit on behalf of the KGen Companies, Docket No .ER04-1181 et al., market-based rate change in status filing, April 2, 2009.
- Affidavit on behalf of Victory Garden Phase IV, LLC, Sky River LLC, FPL Energy Cabazon Wind LLC, Docket Nos. ER09-900-902, market-based rate application, April 1, 2009.
- Affidavit on behalf of the KGen Companies, Docket No. EC07-30 et al., March 31, 2009.
- Affidavit on behalf of TransAlta Energy Marketing Corporation, Docket No. ER09-884, market-based rate application, March 25, 2009.
- Affidavit on behalf of NorthWestern Energy, Docket No. ER03-329, triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Calpine Corporation re Broad River Energy LLC et al., Docket No. ER00-38 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of LS Power Marketing, LLC, Docket No. ER96-1947 et al., triennial market-based rate update, December 29, 2008.
- Affidavit on behalf of Tenaska Alabama Partners, L.P., et al., Docket No. ER00-840 et al., triennial market-based rate update, December 24, 2008.
- Affidavit on behalf of Bluegrass Generation Company, LLC., et al., Docket No. ER02-506 et al., triennial market-based rate update, December 24, 2008
- Affidavit on behalf of KGen Hinds, LLC, et al., Docket No. ER04-1181 et al., triennial market-based rate update, December 23, 2008
- Affidavit on behalf of Reliant SE MBR Entities, FERC Docket No. ER05-143 et al., triennial market-based rate update, December 23, 2008.

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- Affidavit on behalf of Exelon Generation Company, LLC, Docket No. ER00-3251 triennial market-based rate update, December 18, 2008.
- Affidavit on behalf of Northern Indiana Public Service Co. et al., Docket No. ER00-2173 et al., triennial market-based rate update, December 18, 2008.
- Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER07-189 et al., triennial market-based rate update, December 17, 2008.
- Affidavit on behalf of Shady Hills Power Company, LLC, Docket No. ER02-527, triennial market-based rate update, December 4, 2008.
- Affidavit on behalf of Farmers City Wind, LLC, Docket No. ER09-31, market-based rate application, October 6, 2008.
- Affidavit on behalf of Elm Creek Wind, LLC, Docket No. ER09-30, market-based rate application, October 6, 2008.
- Affidavit on behalf of Dynegy Marketing and Trade, Docket No. ER09-20, market-based rate application, October 6, 2008.
- Affidavit on behalf of LS Power Development, LLC and Luminus Management, LLC, Docket No. EC08-126, September 24, 2008.
- Affidavit on behalf of Public Utility District 2 of Grant County, WA, in NorthWestern Corporation, in connection with market-based rates for ancillary services, Docket No. ER08-1529, September 12, 2008.
- Affidavit on behalf of LG&E Energy Marketing Inc. et al., Docket No. ER94-1188 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Calpine Corporation re Bethpage Energy Center 3, LLC et al., Docket No. ER04-1099 et al., September 2, 2008.
- Supplemental Affidavit on behalf of Virginia Electric and Power Co. et al., Docket No. ER01-468 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of South Carolina Electric & Gas Company, Docket No. ER96-1085, triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Progress Energy Inc. et al., Docket No. ER99-2311 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of the EME Companies, Docket No. ER96-2652 et al., triennial market-based rate update, August 29, 2008.

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- Affidavit on behalf of Bridgeport Energy, LLC et al., Docket No. ER98-2783. triennial market-based rate update, August 29, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER07-188, triennial market-based rate update, August 29, 2008.
- Supplemental Affidavit on behalf of PHI Entities, Docket No. ER96-1361 et al., triennial market-based rate update, August 21, 2008.
- Supplemental Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, August 18, 2008.
- Supplemental Affidavit on behalf of Exelon MBR Companies, Docket No. ER00-3251 et al., triennial market-based rate update, August 15, 2008.
- Affidavit on behalf of Fowler Ridge Wind Farm, LLC, Docket No. ER08-1323, application for market-based rates, August 1, 2008.
- Affidavit on behalf of FPL Energy, LLC, Docket No. ER08-1300 et al., application for market-based rates, July 24, 2008.
- Affidavit on behalf of Naturener Montana Wind Energy, LLC, Docket No. ER08-1261, application for market-based rates, July 15, 2008.
- Affidavit on behalf of FPLE Companies, FERC Docket No. ER02-2559 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Duke Energy MBR Companies, FERC Docket No. ER07-189 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Bear Energy LP et al., FERC Docket No. ER06-864 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Reliant NE MBR Entities, FERC Docket No. ER00-2129 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Noble Altona Windpark, LLC et al., FERC Docket No. ER06-1409 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of NRG Companies, FERC Docket No. ER97-4281 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of BG Dighton Power, LLC et al., FERC Docket No. ER06-1367 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Mirant Canal, LLC et al., FERC Docket No. ER01-1268 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of CPV Liberty, LLC, FERC Docket No. ER07-1193, triennial market-based rate update, June 30, 2008.

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- Affidavit on behalf of Tenaska Energy, Inc. et al., FERC Docket No. ER02-24 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Birchwood Power Partners LP et al., FERC Docket No. ER07-501 et al., triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Wisconsin Electric Power Company, FERC Docket No. ER08-1176, application for market-based rates, June 27, 2008.
- Affidavit on behalf of New Athens Generating Co., LLC and Millennium Power Partners, LP, triennial market-based rate update, FERC Docket No. ER98-830 et al., June 27, 2008.
- Affidavit on behalf of Granite Ridge Energy, LLC, FERC Docket No. ER05-287, triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Astoria Generating Co. LP et al., FERC Docket No. ER99-3168 et al., triennial market-based rate update, June 24, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, FERC Docket No. EC08-94, application for sale of jurisdictional assets, May 30, 2008.
- Supplemental Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., triennial market-based rate update, FERC Docket No. ER98-1466, April 21, 2008.
- Supplemental Affidavit on behalf of Baltimore Gas and Electric Company et al., triennial market-based rate update, FERC Docket No. ER99-2948, April 21, 2008.
- Affidavit on behalf of JPMorgan Chase & Co. and The Bear Stearns Companies Inc., application for sale of jurisdictional assets, FERC Docket No. EC08-66, March 31, 2008.
- Affidavit on behalf of Oklahoma Gas & Electric Company, et al., application for sale of jurisdictional assets, FERC Docket No. EC08-58, March 20, 2008.
- Affidavit on behalf of NRG Southaven, LLC et al., FERC Docket No. EC08-57, March 20, 2008.
- Affidavit on behalf of Shell Energy North America (US), LP, application for market-based rates, FERC Docket No. ER08-656, March 11, 2008.
- Affidavit on behalf of EFS Parlin Holdings, LLC, application for market-based rates, FERC Docket No. ER08-649, March 10, 2008.
- Affidavit on behalf of Safe Harbor Power Corporation, application for market-based rates, FERC Docket No. ER08-537, February 5, 2008.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC et al., FERC Docket No. ER02-1633, change in status, January 31, 2008.
- Affidavit on behalf of Calpine Corp. and LS Power Development, LLC et al., FERC Docket No. EC08-39-000, January 22, 2008.
- Supplemental Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, January 15, 2008.

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- Affidavit on behalf of AES Western Wind MV Acquisition, Docket No. EC08-37, January 15, 2008.
- Affidavit on behalf of Dominion Energy Marketing, Inc. et al., application for market-based rate authority, FERC Docket No. ER01-468, January 14, 2008.
- Affidavit on behalf of Baltimore Gas and Electric Company et al., updated market-based rate filing, FERC Docket No. ER99-2948, January 14, 2008.
- Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., updated market-based rate filing, FERC Docket No. ER98-1466, January 14, 2008.
- Affidavit on behalf of Exelon Generation Company, LLC et al., updated market-based rate filing, FERC Docket No. ER00-3251, January 14, 2008.
- Affidavit on behalf of Pepco Holdings, Inc., et al., updated market-based rate filing, FERC Docket No. ER96-1361, January 14, 2008.
- Affidavit on behalf of Green Mountain Power Corporation, updated market-based rate filing, FERC Docket No. ER01-0989, January 14, 2008.
- Affidavit on behalf of Duquesne Light Company et al., updated market-based rate filing, FERC Docket No. ER98-4159 et al., January 11, 2008.
- Affidavit on behalf of Central Hudson Gas and Electric Corporation, updated market-based rate filing, FERC Docket No. Docket No. ER97-2872 et al., January 11, 2008.
- Affidavit on behalf of Bicent (California) Malburg, LLC, application for market-based rate authority, FERC Docket No. ER08-314-000, December 7, 2007.
- Affidavit on behalf of Northern Indiana Public Service Co. and Broadway Gen Funding, LLC, application and related exhibits requesting authorization for a transaction to transfer a generating facility, FERC Docket No. EC08-21-000, December 6, 2007.
- Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, November 21, 2007.
- Affidavit on behalf of Calpine Corp. and Harbinger Capital Partners Master Fund I, Ltd. et al., joint application for approval of the proposed distribution of common stock of a reorganized Calpine to Acquirors, FERC Docket No. EC08-15-000, November 16, 2007.
- Affidavit on behalf of Waterbury Generation, LLC, application for market-based rate authority, FERC Docket No. ER08-200-000, November 9, 2007.
- Affidavit on behalf of FPL Energy Oliver Wind II, LLC, application for market-based rate authority, FERC Docket No. ER08-197-000, November 8, 2007.
- Affidavit on behalf of Central Power & Lime, Inc., application for market-based rate authority, FERC Docket No. ER08-148-000, November 1, 2007.
- Affidavit on behalf of Gilberton Power Company, application for market-based rate authority, FERC Docket No. ER08-83-000, October 23, 2007.

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- Affidavit on behalf of Black Bayou Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-451, September 25, 2007.
- Affidavit on behalf of NedPower Mount Storm, LLC, application for market-based rate authority, FERC Docket No. ER07-1306-000, August 23, 2007.
- Affidavit on behalf of Sempra Energy Trading Corp. in connection with market-based rate authority, FERC Docket No. ER03-1413-005, July 25, 2007.
- Affidavit on behalf of KGen Acquisition I, LLC et al., application for disposition of jurisdictional facilities, FERC Docket No. EC07-116-000, July 13, 2007.
- Supplemental Affidavit on behalf of Williams Power Company, Inc., application for market-based rate authority, FERC Docket No. EC07-106-000, June 28, 2007.
- Affidavit on behalf of Williams Power Co, Inc and Bear Energy LP, joint application for authorization of the disposition of jurisdictional facilities, FERC Docket No. EC07-106-000, June 14, 2007.
- Affidavit on behalf of Bluegrass Generation Company, LLC et al., notice of non-material change in status, FERC Docket No. ER02-506-008 et al., May 31, 2007.
- Affidavit on behalf of BG Dighton Power, LLC et al., notice of non-material change in status, FERC Docket Nos. ER06-1367-003 et al., May 30, 2007.
- Affidavit on behalf of FPL Energy Point Beach, LLC, application for market-based rate authority, FERC Docket No. ER07-904-000, May 16, 2007.
- Affidavit on behalf of Copiah Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No, CP02-24, March 29, 2007.
- Affidavit on behalf of NRG Power Marketing, Inc. and thirty-one affiliates most of which own generating facilities, triennial market power update and notice of change in status, FERC Docket Nos. ER97-4281-016 et al., March 26, 2007.
- Affidavit on behalf of Egan Hub Storage, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-88, February 20, 2007.
- Affidavit on behalf of Wisconsin Electric Power Co. and FPL Energy Point Beach, LLC, joint application for authorization to dispose of jurisdictional facilities, FERC Docket No. EC07-57-000, February 1, 2007.
- Affidavit on behalf of Lake Road Generating Company, LP et al., joint application for authorization of the disposition of jurisdictional facilities pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-50-000, January 22, 2007.
- Affidavit on behalf of Exelon Generation Company, LLC et al., notice of non-material change in status, FERC Docket Nos. ER00-3251-013 et al., December 15, 2006.
- Revised Affidavit on behalf of Calpine Energy Services, LP, triennial market analysis, FERC Docket No. ER00-3562-004, December 13, 2006.

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- Affidavit on behalf of Dynegy Entities and LSP Entities, notice of non-material change in status, FERC Docket Nos. ER02-506-007 et al., November 2, 2006.
- Affidavit on behalf of Wisconsin Energy Corp.'s, Wisconsin Electric Power Co. et al. for authorization to dispose of jurisdictional facilities, FERC Docket No. ER07-14-000, November 2, 2006.
- Affidavit on behalf of Calpine Energy Services, LP, updated triennial market power analysis, FERC Docket No. ER00-3562-004, October 30, 2006.
- Affidavit on behalf of Dynegy, application for authorization of transactions pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-9-000, October 26, 2006.
- Affidavit on behalf of Coral Power, LLC et al., triennial updated market analysis, FERC Docket Nos. ER96-25-028 et al., October 23, 2006.
- Affidavit on behalf of Westar Energy, Inc. and Kansas Gas and Electric, request for rehearing, FERC Docket Nos. ER03-9-007 et al., October 6, 2006.
- Affidavit on behalf of The Empire District Electric, request for rehearing, FERC Docket Nos. ER99-1757-011 et al., September 14, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp., errata to its 7/31/06 triennial market power update, FERC Docket No. ER01-48-007, September 11, 2006.
- Affidavit on behalf of FPLE Companies, joint triennial market power update, FERC Docket Nos. ER02-2559-007 et al., August 28, 2006.
- Affidavit on behalf of FPL Energy Oliver Wind, LLC application for market-based rates, FERC Docket No. ER06-1392-000, August 23, 2006.
- Affidavit on behalf of The Constellation MBR Entities, errata to their joint triennial market power update submitted on 8/14/06, FERC Docket Nos. ER99-2948-009 et al., August 16, 2006.
- Affidavit on behalf of Constellation MBR Entities, joint triennial market power update, FERC Docket Nos. ER99-2948-009 et al., August 14, 2006.
- Affidavit on behalf of Sempra Energy Trading Corp., updated market analysis, FERC Docket No. ER03-1413-005, August 1, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp, triennial market power analysis in support of its continued authority to sell power at market-based rates, FERC Docket No. ER01-48-007, July 31, 2006.
- Affidavit on behalf of Reliant Energy Power Supply, LLC, application for market-based rates, FERC Docket No. ER06-1272-000, July 20-21, 2006.
- Affidavit on behalf of Lincoln Generating Facility, LLC, fka Allegheny Energy Supply, updated generation market power study, FERC Docket No. ER05-524-001, June 19, 2006.

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- Affidavit on behalf of Alcoa Power Generating, Inc & Alcoa Power Marketing, Inc., amendment to triennial, updated market analysis under ER02-2074 et al., FERC Docket Nos. ER02-2074-002 et al., May 17, 2006.
- Affidavit on behalf of Alcoa Power Generating, Inc. and Alcoa Power Marketing, Inc., updated market analysis of the triennial review of market-based rate authority, FERC Docket Nos. ER02-2074-002 et al., April 13, 2006.
- Affidavit on behalf of Morgan Energy Center, LLC et al., Calpine Gilroy Cogen, LP, Los Medanos Energy Center, LLC, and KIAC Partners et al., market-based rate filings, FERC Docket Nos. ER06-741-000 et al., March 16, 2006.
- Affidavit on behalf of Midland Cogeneration Venture Limited Partnership, market-based rate application, FERC Docket No. ER06-733-000, March 15, 2006.
- Affidavit on behalf of Duke Power Co, LLC et al., notice of change in status filing, FERC Docket Nos. ER96-110-020 et al., March 1, 2006.
- Affidavit on behalf of Westar Energy Inc & ONEOK Energy Services Co, LP, answer to protests filed by Oklahoma Municipal Power Authority et al., FERC Docket No. ER06-48-000, February 21, 2006.
- Affidavit on behalf of Edgecombe Genco, LLC and Spruance Genco, LLC, market-based rate application, FERC Docket No. ER06-635-000 and ER06-634-000, February 13, 2006.
- Affidavit on behalf of NRG Energy, Inc. et al., joint application for authorization under Section 203 of the Federal Power Act to transfer jurisdictional facilities, FERC Docket No. EC06-66-000, January 20, 2006.
- Affidavit on behalf of Westar Energy, Inc. et al. joint application for authorization under Section 203 of the Federal Power Act for the disposition of jurisdictional facilities, FERC Docket No. EC06-48-000, December 21, 2005.
- Affidavit on behalf of Calpine Energy Center, LLC, joint updated market power analysis, FERC Docket Nos. ER02-2227-003 et al., August 30, 2005.
- Affidavit on behalf of Allegheny Power, Allegheny Energy Supply Co., LLC, Allegheny Energy Supply Gleason Generating Facility, Inc et al., combined triennial market power report, FERC Docket Nos. ER98-1466-003 et al., August 11, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, filed on 5/3/05, FERC Docket Nos. ER02-1257-003 et al., August 5, 2005.
- Affidavit on behalf of MidAmerican Energy Co., in connection with market-based rate update, FERC Docket No. ER96-719-006, August 1, 2005.
- Affidavit on behalf of Occidental Power Services Inc., updated market power analysis, FERC Docket No. ER02-1947-006, August 1, 2005.

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- Affidavit on behalf of FPL Energy Duane Arnold LLC, joint application for approval of disposition of jurisdictional facilities, FERC Docket Nos. EC05-114-000 et al., July 29, 2005.
- Affidavit on behalf of FPL Energy Duane Arnold, LLC, authorization to sell at market-based rates, FERC Docket No. ER05-1281-000, July 29, 2005.
- Affidavit on behalf of MidAmerican Energy Holdings Co. et al., application for approval of disposition of jurisdictional facilities under Section 203 of the Federal Power Act, FERC Docket No. EC05-110-000, July 22, 2005.
- Affidavit on behalf of Calpine Entities, joint updated market power analysis, FERC Docket Nos. EC02-1367-003 et al., July 18, 2005.
- Affidavit on behalf of Bayonne Plant Holding, LLC, as successor in interest of Cogen Technologies NJ Venture et al.,, as successor in interest to Camden Cogen et al., triennial updated market analysis, FERC Docket Nos. EC02-1486-003 et al., July 15, 2005.
- Affidavit on behalf of Cabazon Wind Partners, LLC & Whitewater Hill Wind Partners, consolidated triennial updated market analysis, FERC Docket Nos. ER02-1695-003 et al., June 24, 2005.
- Affidavit on behalf of TransAlta Energy Marketing (U.S.) Inc. et al., in connection with market-based rate authority, FERC Docket Nos. ER05-1014-000 et al., May 24, 2005.
- Affidavit on behalf of Minergy Neenah, LLC, updated triennial market power analysis, FERC Docket No. ER99-3125-001, May 16, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, FERC Docket Nos. ER02-1257-002 et al., May 3, 2005.
- Affidavit on behalf of CES Marketing VI, LLC et al., market-based rate application, FERC Docket Nos. ER05-816-000 et al., April 13, 2005.
- Affidavit on behalf of Onondaga Cogeneration Limited Partnership, triennial updated market analysis, FERC Docket No. ER00-895-006, March 24, 2005.
- Affidavit on behalf of The Williams Entities' (Williams Power Co. Inc. et al.), joint triennial market power update, FERC Docket Nos. ER03-1331-004 et al., March 24, 2005.
- Affidavit on behalf of J Aron & Co and Power Receivable Finance LLC, errata to triennial updated market analysis submitted on 12/30/04, FERC Docket Nos. ER02-237-003 et al., February 25, 2005.
- Affidavit on behalf of Delta Energy Center, LLC, updated power analysis, FERC Docket No. ER02-600-003, February 14, 2005.
- Affidavit on behalf of Wisconsin Electric Power Company, market-based rate filing, FERC Docket No. ER05-540-000, February 4, 2005.
- Affidavit on behalf of J Aron & Co. and Power Receivable Finance, LLC, consolidated triennial updated market analysis, December 30, 2004.

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- Affidavit on behalf MidAmerican Energy Co., supplement to 10/29/04 market-power update filing, FERC Docket No. ER96-719-004, November 23, 2004.
- Affidavit in connection with Comments of Cinergy Services, Inc. re Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority under RM04-14, FERC Docket No. RM04-14-000, November 15, 2004.
- Affidavit on behalf of Metcalf Energy Center, LLC and Pastoria Energy Center, LLC, market-based rate application, FERC Docket No. ER05-68-000 and ER05-67-000, October 25, 2004.
- Affidavit on behalf Calpine Bethpage 3, LLC and TBG Cogen Partners, market-based rate filing, FERC Docket No. ER05-48-000 and ER04-1100-000, August 4, 2004.
- Affidavit on behalf of The Empire District Electric Co., updated market power analysis, FERC Docket No. ER99-1757-005, September 27, 2004.
- Affidavit on behalf of Wisconsin Electric Power Co, revised generation market power portion of its pending three-year market power update, FERC Docket No. ER98-855-004, September 27, 2004.
- Affidavit on behalf of Duke Power, a Division of Duke Energy Corp., market power analysis, FERC Docket No. ER96-110-010, August 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co et al., application for the proposed transfer of substantially all of the assets of Multitrade to Dominion Power, FERC Docket No. EC04-139-000, July 30, 2004.
- Affidavit on behalf of Goldendale Energy Center, market-based rate application, FERC Docket No. ER04-1038-000, July 23, 2004.
- Affidavit on behalf of Calumet Energy Team, LLC, updated triennial market power analysis, FERC Docket No. ER01-389-001, July 20, 2004.
- Affidavit on behalf of Calpine Parlin, LLC, market-based rate filing, FERC Docket No. ER04-832-000, May 11, 2004.
- Affidavit on behalf of Calpine Newark, LLC, market-based rate filing, FERC Docket No. ER04-831-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co, application for market-based rates, FERC Docket No. ER04-834-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric and Power Co., UAE Mecklenburg Cogeneration, LP et al., authorization for the proposed transfer of 100% of the ownership interests of Cogenco etc., FERC Docket No. EC04-104-000, May 6, 2004.
- Affidavit on behalf of Occidental Power Marketing, LP, triennial market power analysis, FERC Docket No. ER99-3665-004, April 14-15, 2004.
- Affidavit on behalf of The Williams Entities, joint triennial market power update, FERC Docket Nos. ER03-1331-003 et al., March 12, 2004.

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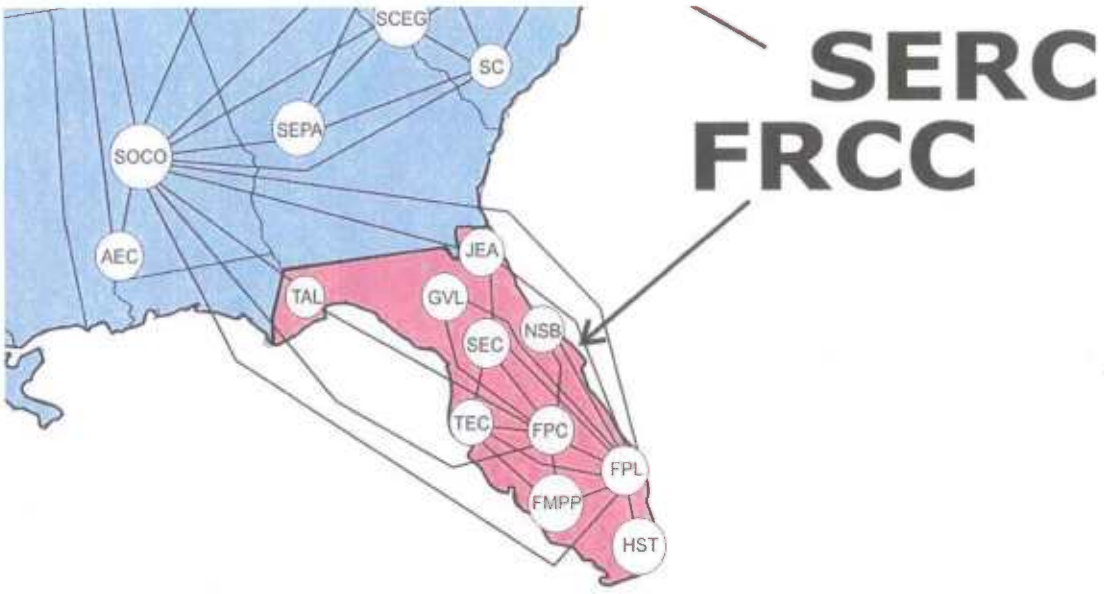
- Affidavit on behalf of Wisconsin Electric Power Co., updated triennial market-power analysis, FERC Docket No. ER98-855-003, January 29, 2004.
- Affidavit on behalf of GEN~SYS Energy, triennial update market power analysis, FERC Docket No. ER97-4335-006, October 17, 2003.
- Affidavit on behalf of Calpine Energy Services LP, updated market power analysis, FERC Docket No. ER00-3562-001, September 22, 2003.
- Affidavit on behalf of Rocky Mountain Energy Center, LLC, application for market-based rates, FERC Docket No. ER03-1288-000, September 3, 2003.
- Affidavit on behalf of Fox Energy Co, LLC, application for market-based rates, FERC Docket No. ER03-983-000, June 24, 2003.
- Affidavit on behalf of Chehalis Power Generating Limited Partnership, application for market-based rates etc., FERC Docket No. ER03-717-000, April 7, 2003.
- Affidavit on behalf of Calpine Northbrook Energy Marketing, LLC, triennial updated market power analysis, FERC Docket No. ER03-717-000, October 23, 2002.
- Affidavit on behalf of Choctaw Generation Limited Partnership, updated triennial market power analysis, FERC Docket No. ER98-3774-001, October 17, 2002.
- Affidavit on behalf of Riverside Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-49-000, October 16, 2002.
- Affidavit on behalf of Blue Spruce Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-25-000, October 8, 2002.
- Prepared Responsive Testimony on behalf of Calpine Energy Services, LP et al. re: San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Services etc. under EL00-95 et al., FERC Docket Nos. EL00-95-045 et al., September 27, 2002.
- Affidavit on behalf of Duke Power Co., a division of Duke Energy Corp., market-based rate filing, FERC Docket No. ER96-110-007, December 17, 2001.

NERC "Bubble" Diagram of BAAs (Excerpt)



As of March 1, 2014

http://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/BA_Bubble_Map_20140305.jpg

Abbreviation	Utility	Abbreviation	Utility
JEA	JEA	FPC	DEF – Duke Energy Florida
GVL	Gainesville Regional Utilities	FPL	Florida Power & Light
TAL	City of Tallahassee	FMPP	Florida Municipal Power Pool
SEC	Seminole Electric Cooperative	HST	Homestead Energy Services
TEC	Tampa Electric Company	NSM	New Smyrna Beach

Illustrative HHI Calculations

Market X - 1 Supplier				Market Y - 4 Equal Suppliers				Market Y – B+C Merge			
	MW	Share	HHI		MW	Share	HHI		MW	Share	HHI
Co. A	12,000	100%	10,000	Co. B	3,000	25%	625	Co. B/C	6,000	50%	2500
				Co. C	3,000	25%	625				
				Co. D	3,000	25%	625	Co. D	3,000	25%	625
				Co. E	3,000	25%	625	Co. E	3,000	25%	625
Total	12,000	100%	10,000	Total	12,000	100%	2500	Total	12,000	100%	3750
								HHI Change:			1250

HHI Standards as Applied by FERC

	Unconcentrated	Moderately Concentrated	Highly Concentrated	
Post-Merger HHI	< 1000	1000-1800	>1800	
Change in HHI	Any change	>100	> 50	>100
Potential Merger Effect	Unlikely to have adverse competitive effects	Potentially raises significant competitive concerns	Potentially raises significant competitive concerns	Likely to create or enhance market power

Time Period Definitions Used in Competitive Analysis Screen

SUMMER (June-July-August)

Super Peak 1 (S_SP1):	Top load hour
Super Peak 2 (S_SP2):	Top 10% of peak load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

Super Peak (W_SP):	Top 10% of peak load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November)

Super Peak (SH_SP):	Top 10% of peak load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

"AEC Facts" for DEF (EQR Prices)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Load(MW)	9,185	8,360	6,264	5,070	5,956	4,501	3,786	7,374	5,174	4,195
Price	$200	$63	$47	$43	$70	$43	$38	$51	$39	$37
Price x 1.05	$210	$66	$49	$45	$74	$45	$40	$54	$41	$39
Total Generation & LT Purchases (MW)	10,228	10,228	10,228	10,228	10,460	10,460	10,460	9,651	9,651	9,651
Economic Capacity (MW)	9,117	8,210	6,113	5,037	9,032	5,055	2,220	5,552	3,675	2,072
Available Economic Capacity (MW)	-	-	-	-	3,077	554	-	-	-	-

"AEC Facts" for DEF (EQR Prices +10%)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Load(MW)	9,185	8,360	6,264	5,070	5,956	4,501	3,786	7,374	5,174	4,195
Price	$220	$69	$52	$47	$77	$47	$42	$56	$43	$41
Price x 1.05	$231	$73	$54	$50	$81	$50	$44	$59	$45	$43
Total Generation & LT Purchases (MW)	10,228	10,228	10,228	10,228	10,460	10,460	10,460	9,651	9,651	9,651
Economic Capacity (MW)	9,117	9,005	6,121	6,113	9,032	6,047	5,055	7,293	4,647	4,647
Available Economic Capacity (MW)	-	645	-	1,044	3,077	1,546	1,269	-	-	452

"AEC Facts" for DEF (a comparison of EQR Prices and EQR Prices + 10%)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Price	$200	$63	$47	$43	$70	$43	$38	$51	$39	$37
Available Economic Capacity (MW)	-	-	-	-	3,077	554	-	-	-	-
Price	$220	$69	$52	$47	$77	$47	$42	$56	$43	$41
Available Economic Capacity (MW)	-	645	-	1,044	3,077	1,546	1,269	-	-	452
Change in AEC (MW)	-	645	-	1,044	-	992	1,269	-	-	452

AEC Results for DEF (Acquisition 1 (EQR Prices))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 200	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 63	-	0.0%	436	17.0%	2,569	1,149	285	11.8%	2,418	1,111	(38)
S_P	$ 47	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
S_OP	$ 43	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
W_SP	$ 70	3,077	68.6%	400	8.9%	4,486	4,877	3,476	77.5%	4,486	6,098	1,221
W_P	$ 43	554	39.0%	-	0.0%	1,419	2,369	554	39.0%	1,419	2,369	-
W_OP	$ 38	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
SH_SP	$ 51	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_P	$ 39	-	0.0%	-	0.0%	2,121	2,258	-	0.0%	2,121	2,258	-
SH_OP	$ 37	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-

AEC Results for DEF (Acquisition 2 (EQR Prices))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2		DEF						
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 200	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 63	-	0.0%	70	2.7%	2,569	1,149	412	17.0%	2,418	1,144	(5)
S_P	$ 47	-	0.0%	59	2.8%	2,130	1,268	412	20.8%	1,980	1,226	(41)
S_OP	$ 43	-	0.0%	59	2.8%	2,130	1,268	531	25.3%	2,098	1,345	78
W_SP	$ 70	3,077	68.6%	4	0.1%	4,486	4,877	3,602	72.6%	4,960	5,416	540
W_P	$ 43	554	39.0%	3	0.2%	1,419	2,369	1,080	57.0%	1,893	3,726	1,357
W_OP	$ 38	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
SH_SP	$ 51	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_P	$ 39	-	0.0%	85	4.0%	2,121	2,258	-	0.0%	1,643	2,179	(79)
SH_OP	$ 37	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-

AEC Results for DEF (Acquisition 1 (+10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 220	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 69	645	20.1%	436	13.6%	3,214	1,137	1,080	33.6%	3,214	1,681	544
S_P	$ 52	-	0.0%	-	0.0%	2,133	1,264	-	0.0%	2,133	1,264	-
S_OP	$ 47	1,044	32.9%	-	0.0%	3,174	1,652	1,044	32.9%	3,174	1,652	-
W_SP	$ 77	3,077	68.6%	400	8.9%	4,486	4,877	3,476	77.5%	4,486	6,098	1,221
W_P	$ 47	1,546	60.6%	-	0.0%	2,553	3,959	1,546	60.6%	2,553	3,959	-
W_OP	$ 42	1,269	59.5%	-	0.0%	2,134	3,910	1,269	59.5%	2,134	3,910	-
SH_SP	$ 56	-	0.0%	364	13.2%	2,759	1,549	282	10.5%	2,677	1,572	22
SH_P	$ 43	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_OP	$ 41	452	17.6%	-	0.0%	2,573	1,843	452	17.6%	2,573	1,843	-

AEC Results for DEF (Acquisition 1 (+20% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 240	1,043	28.5%	436	11.9%	3,655	1,417	1,479	40.5%	3,655	2,097	680
S_SP2	$ 76	645	20.1%	436	13.6%	3,214	1,137	1,080	33.6%	3,214	1,681	544
S_P	$ 56	1,788	41.0%	436	10.0%	4,357	2,087	2,224	51.0%	4,357	2,908	821
S_OP	$ 52	1,051	33.0%	-	0.0%	3,184	1,657	1,051	33.0%	3,184	1,657	-
W_SP	$ 84	3,107	68.8%	400	8.8%	4,517	4,903	3,506	77.6%	4,517	6,120	1,217
W_P	$ 52	1,554	60.7%	-	0.0%	2,561	3,971	1,554	60.7%	2,561	3,971	-
W_OP	$ 46	2,261	69.2%	-	0.0%	3,268	4,965	2,261	69.2%	3,268	4,965	-
SH_SP	$ 61	31	1.1%	364	13.0%	2,790	1,494	394	14.1%	2,790	1,523	29
SH_P	$ 47	372	13.4%	-	0.0%	2,764	1,552	372	13.4%	2,764	1,552	-
SH_OP	$ 44	1,350	36.1%	-	0.0%	3,742	2,049	1,350	36.1%	3,742	2,049	-

AEC Results for DEF (Acquisition 1 (-10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 180	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 57	-	0.0%	436	17.0%	2,569	1,159	127	5.6%	2,260	1,158	(2)
S_P	$ 42	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
S_OP	$ 39	-	0.0%	-	0.0%	1,822	1,612	-	0.0%	1,822	1,612	-
W_SP	$ 63	2,096	59.8%	400	11.4%	3,505	3,859	2,495	71.2%	3,505	5,222	1,363
W_P	$ 39	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
W_OP	$ 34	-	0.0%	-	0.0%	699	3,142	-	0.0%	699	3,142	-
SH_SP	$ 46	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_P	$ 35	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-
SH_OP	$ 33	-	0.0%	-	0.0%	2,109	2,512	-	0.0%	2,109	2,512	-

AEC Results for DEF (Acquisition 2 (+10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 220	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 69	645	20.1%	70	2.2%	3,214	1,137	1,208	37.6%	3,214	1,896	759
S_P	$ 52	-	0.0%	59	2.8%	2,133	1,264	420	21.1%	1,990	1,229	(35)
S_OP	$ 47	1,044	32.9%	59	1.9%	3,174	1,652	1,607	50.6%	3,174	2,870	1,218
W_SP	$ 77	3,077	68.6%	4	0.1%	4,486	4,877	3,602	72.6%	4,960	5,416	540
W_P	$ 47	1,546	60.6%	3	0.1%	2,553	3,959	2,072	68.4%	3,027	4,892	932
W_OP	$ 42	1,269	59.5%	3	0.2%	2,134	3,910	1,795	68.8%	2,608	4,985	1,075
SH_SP	$ 56	-	0.0%	85	3.1%	2,759	1,549	397	14.8%	2,677	1,268	(282)
SH_P	$ 43	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_OP	$ 41	452	17.6%	85	3.3%	2,573	1,843	930	36.2%	2,573	2,196	352

AEC Results for DEF (Acquisition 2 (+20% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 240	1,043	28.5%	70	1.9%	3,655	1,417	1,606	43.9%	3,655	2,319	902
S_SP2	$ 76	645	20.1%	70	2.2%	3,214	1,137	1,208	37.6%	3,214	1,896	759
S_P	$ 56	1,788	41.0%	59	1.4%	4,357	2,087	2,351	54.0%	4,357	3,176	1,088
S_OP	$ 52	1,051	33.0%	59	1.9%	3,184	1,657	1,614	50.7%	3,184	2,875	1,219
W_SP	$ 84	3,107	68.8%	4	0.1%	4,517	4,903	3,632	72.8%	4,990	5,439	535
W_P	$ 52	1,554	60.7%	3	0.1%	2,561	3,971	2,079	68.5%	3,034	4,901	930
W_OP	$ 46	2,261	69.2%	3	0.1%	3,268	4,965	2,787	74.5%	3,742	5,682	717
SH_SP	$ 61	31	1.1%	102	3.6%	2,790	1,494	509	18.3%	2,790	1,284	(210)
SH_P	$ 47	372	13.4%	85	3.1%	2,764	1,552	850	30.8%	2,764	1,756	205
SH_OP	$ 44	1,350	36.1%	85	2.3%	3,742	2,049	1,829	48.9%	3,742	2,830	780

AEC Results for DEF (Acquisition 2 (-10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 180	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 57	-	0.0%	59	2.3%	2,569	1,159	254	11.3%	2,260	1,106	(53)
S_P	$ 42	-	0.0%	59	2.8%	2,130	1,268	-	0.0%	1,567	1,264	(3)
S_OP	$ 39	-	0.0%	59	3.3%	1,822	1,612	-	0.0%	1,259	1,706	94
W_SP	$ 63	2,096	59.8%	4	0.1%	3,505	3,859	2,621	65.9%	3,979	4,560	701
W_P	$ 39	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
W_OP	$ 34	-	0.0%	-	0.0%	699	3,142	-	0.0%	699	3,142	-
SH_SP	$ 46	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_P	$ 35	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-
SH_OP	$ 33	-	0.0%	-	0.0%	2,109	2,512	-	0.0%	2,109	2,512	-

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

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

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

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

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

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

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

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

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

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

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CERTIFICATE OF SERVICE

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

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

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

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

DEF's Near Term Summer And Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,8 70	8,812	39,801
2015	9,133	9,042	40,490
2016	9,370	9,149	41,098
2017	9,298	9,307	41,375

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

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

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

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

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

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

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

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

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

Q. Why did FERC adopt the Competitive Analysis Screen?

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

FILED JAN 30, 2015
DOCUMENT NO. 00690-15
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING

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

Respectfully submitted this 30th day of January, 2015.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 16
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

REDACTED

REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

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

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. 140111-EI

REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH

I. INTRODUCTION AND PURPOSE OF REBUTTAL TESTIMONY.

Q. Please state your name and business address.

A. My name is Benjamin M.H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. What is your position with Duke Energy?

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

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

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

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

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

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

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

what Calpine filed for Mr. Thornton in Docket No. 140110-EI. My rebuttal testimony in Docket No. 140110-EI addresses the direct testimony and exhibits filed by the Calpine and NRG witnesses in that Docket. The purpose of this rebuttal testimony is to respond to the direct testimony, exhibits, and recommendations of the Calpine and NRG witnesses in this Docket.

II. ORGANIZATION AND SUMMARY OF REBUTTAL TESTIMONY.

Q. How is your rebuttal testimony organized?

A. The first part of my rebuttal testimony in this Docket addresses Calpine's and NRG's new and different proposals to meet DEF's customer needs for generation capacity prior to 2018. To explain briefly, the Calpine witnesses rely in their direct testimony on a proposal to meet DEF's need prior to 2018 that was submitted to DEF after DEF filed its direct testimony and exhibits in this Docket. This proposal is different from the Calpine proposal that was submitted to and evaluated by DEF, and that is discussed in my direct testimony and exhibits in this Docket. NRG likewise submitted a new and slightly different proposal from the proposal that was submitted to, evaluated by, and addressed by DEF in my direct testimony and exhibits, but it is not clear from NRG's testimony which proposal NRG is now relying on in its direct testimony and exhibits in this Docket. In any event, the first part of my rebuttal testimony explains the history behind why Calpine and NRG made these different, alternative proposals, the discussions between the parties related to these and other proposals made to DEF after DEF filed its Petition, direct

testimony, and exhibits in this Docket, and DEF's evaluation of these different, alternative proposals that demonstrates that, despite NRG's and in particular Calpine's efforts to close the gap between their initial proposals and DEF's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project, their revised proposals, on a quantitative and qualitative basis, still are not the most cost effective generation alternative to meet DEF customer needs prior to 2018.

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

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

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

qualitative assessment of firm natural gas transportation and transmission reliability and costs, respectively, in DEF's evaluation of the most cost effective alternative to meet DEF's need prior to 2018. In addition, Julie Solomon with Navigant Consulting, Inc. has filed rebuttal testimony addressing the NRG and Calpine direct testimony about the FERC Competitive Analysis Screen.

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

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

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

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

NRG witnesses Mr. Pollock and Mr. Dauer claim the NRG plant acquisition proposal – Acquisition 1 – that NRG submitted in response to DEF's request for proposals to meet DEF's need prior to 2018 is more cost effective than the Suwannee Simple Cycle Project based on DEF's initial economic evaluation. NRG ignores the results of DEF's continued quantitative and qualitative evaluation of that proposal that demonstrates the NRG plant acquisition proposal is not more cost effective than the Company's self-build generation projects --- even though Mr. Pollock concedes that DEF must consider quantitative and qualitative factors and should not base its decision on the results of an initial economic analysis. Mr. Pollock and Mr. Dauer ignore the results of DEF's complete evaluation of NRG's proposal because they know the firm gas transportation requirements that DEF requires to rely on the NRG plant as a firm resource to meet DEF's load-serving obligation renders the NRG acquisition proposal uneconomic. Mr. Dauer's claimed ability to operate the NRG plant on non-firm and "spot" market gas transportation arrangements in the past as an Independent Power Producer is not a substitute for DEF's obligations to provide firm power to customers at all times. Further, no NRG witness disputes the fact that the NRG Acquisition 1

proposal failed the FERC Competitive Analysis Screen rendering FERC approval of the NRG plant acquisition unlikely without substantial mitigation. For all these reasons, the Suwannee Simple Cycle Project remains a superior generation capacity resource to the NRG plant acquisition proposal that NRG continues to advance in their testimony to meet DEF's need prior to 2018.

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

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

As a result, the Company decided that, based on the FERC market screen results and the results of its own detailed economic and qualitative analyses, the potential plant acquisitions under the Calpine and NRG initial or

final and best offer proposals are not cost effective for the Company's customers. The Company determined that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are more cost-effective, on a quantitative and qualitative basis, than any of the alternative supply-side generation proposals. DEF requests Commission approval of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation capacity resources to meet DEF's need for generation capacity prior to 2018.

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

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

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

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

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

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

A. NRG AND CALPINE INITIAL GENERATION CAPACITY PROPOSALS.

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

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

a PPA with NRG and Calpine is that DEF's need for generation capacity was changing in this time period. (Borsch Direct Test., pp. 32-33).

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

DEF determined that DEF could reduce this need prior to 2018 by completing projects at CR1 and CR2 and employing site emission averaging at the Crystal River Energy Complex ("CREC") to comply with MATS and extend the operation of CR1 and CR2 to 2018. This plan was presented as a modification to the Company's Integrated Clean Air Compliance Plan to the Commission in December 2013 and approved by the Commission in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI

issued May 9, 2014). (Borsch Direct Test., pp. 8-9). As a result of this plan for the continued operation of CR1 and CR2 beyond 2016, the Company reduced its generation capacity need prior to 2018 from 1,150MW to about 470MW. (Borsch Direct Test., p. 11, lines 14-23).

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

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

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

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

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

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

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

These NRG and Calpine proposals were evaluated in DEF's generation resource options assessment that is described in detail in my direct testimony and exhibits in this Docket. As I explain there, based on that assessment, including all quantitative and qualitative costs and risks, the Company

determined that the most cost effective generation to meet its need prior to 2018 was the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. (Borsch Direct Test., pp. 32-49, Exhibits Nos. ___ (BMHB-7) to ____ (BMHB-11)).

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

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

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

with Navigant Consulting, Inc. to address the FERC Competitive Analysis Screen for both the NRG and Calpine acquisition proposals. These issues associated with the NRG and Calpine acquisition proposals are discussed in my direct testimony. (Borsch Direct Test., pp. 40-43).

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

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

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

to meet its need prior to 2018. Other parties attended this meeting, including Calpine's attorney.

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

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

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

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

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

C. FINAL AND BEST OFFERS.

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

A. No. DEF did not stop taking calls from NRG and Calpine and DEF did not stop communicating with them about their proposals after DEF filed its Petition in this Docket, even though DEF had no obligation to continue such discussions with them. DEF already had informed them about the impediments to selecting their proposals and, although DEF received no response to these impediments prior to DEF filing its Petition in this Docket,

DEF was willing to continue the discussions with them because DEF was genuinely interested in purchasing one of their plants if the purchase made sense and offered superior customer value to the Company's self-build generation options. DEF informed both NRG and Calpine of the continuing discussions with DEF and both parties. DEF encouraged both NRG and Calpine to give DEF a final and best offer for the acquisition of their plants with a plan to deal with any FERC Competitive Analysis Screen issue associated with the plant acquisition.

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

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

Q. Please describe your discussions with NRG.

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

Q. Were there similar discussions between DEF and Calpine?

A. Yes. DEF continued its communications with Calpine to obtain a final and best plant acquisition offer from Calpine. DEF met with Calpine on June 2, 2014 and had follow up conference calls with Calpine on June 9, June 11, and July 1, 2014. DEF provided Calpine with the details of DEF's evaluation of Calpine's acquisition proposal and the economic, qualitative, and FERC

market screen impediments to DEF selecting this acquisition over its self-build generation options. Following each of these meetings DEF analyzed Calpine's alternative proposals to overcome the economic and qualitative impediments to the acquisition of Calpine's plant. DEF also analyzed and provided Calpine its analysis of Calpine's suggested proposals to structure the Calpine plant acquisition in a way that evaded the FERC market screen failures while ensuring that DEF's customers did not incur any costs if FERC approval was not obtained or if FERC required mitigation to eliminate the market screen failures that DEF's expert had identified with the Calpine acquisition. DEF continued correspondence and communications with Calpine about the structure of the Calpine plant acquisition between and after these meeting dates into early July 2014. Copies of the written communications between DEF and Calpine during this period are included as a composite Exhibit No. ___ (BMHB-13) to my rebuttal testimony.

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

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

benefit of DEF's customers that deal would be for the acquisition of either the NRG plant or the Calpine plant.

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

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

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

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

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

1. NRG'S FINAL AND BEST OFFER.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. CALPINE'S FINAL AND BEST OFFER.

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

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

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

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

A. Calpine proposed [redacted]

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

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

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

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

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

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

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

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

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

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

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

A. No. Mr. Hibbard is wrong. First, he fails to include transmission costs to deliver the Calpine plant capacity across TEC's system to DEF that he and Calpine witness Mr. Simpson acknowledge must exist. Second, he fails to include costs that necessarily result from the deferral of the Calpine plant acquisition to a later point in time. Third, he makes an adjustment to DEF's planned firm gas transportation to incorporate the Calpine plant into DEF's generation system that fails to recognize that DEF is operating a generation system to meet its statutory obligation to serve its customers --- not a single combined cycle plant operated on a merchant basis like Calpine --- and actually results in higher future firm gas transportation costs to incorporate that plant into DEF's generation system. Fourth, he fails to include costs that Calpine itself admits exist if DEF defers its self-build generation project in an attempt to obtain FERC approval of the Calpine PPA-acquisition proposal. Finally, Mr. Hibbard ignores qualitative risks that add cost to the Calpine proposed PPA-acquisition, including the assumption that there is no FERC approval or mitigation risk, even though his own client accounted for that risk

in Calpine's July 3rd proposal, albeit in a manner that did not fully address that risk in a cost effective manner. For all these reasons, Mr. Hibbard is wrong and the Calpine July 3rd final and best offer still is not a cost effective option, considering all quantitative and qualitative factors, to meet DEF's need prior to 2018. See Exhibit No. ___ (BMHB-18) to my rebuttal testimony.

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

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

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

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

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

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

No utility with an obligation to serve will rely on transmission operating procedures or the re-dispatch of other generation resources by another utility in an attempt to avoid or limit transmission constraints as firm transmission

generation. That simply is not standard utility practice. Indeed, by re-dispatching generation resources Mr. Simpson means that the utilities are deciding to change the economic dispatch of generation resources just to avoid transmission constraints. This might be a temporary measure by a utility managing its own generation resources to mitigate a limited transmission constraint, but re-dispatching otherwise economically dispatched generation to avoid transmission constraints is obviously not the most cost effective allocation of generation resources. Also the suggestion that re-dispatch may be utilized during peak hours is only feasible if the utilities have sufficient generation flexibility at peak to de-rate selected generation units while still being able to meet peak load. Neither Mr. Simpson nor Mr. Hibbard account for the cost of this inefficient allocation of generation resources in their direct testimony despite advocating this approach and Calpine nowhere in its July 3rd proposal offered to pay DEF and its customers for this cost to accommodate the transmission of Calpine's plant capacity to DEF. As discussed above, DEF in its evaluation modeled this constraint by shaping the available transmission in peak and off-peak months.

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

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

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

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

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

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

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

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

Mr. Hibbard makes an unsupported assumption that the gas transportation contracts which supply the Suwannee site can be redirected to the Calpine Osprey plant location. This is not correct. Different gas

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

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

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

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

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

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

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

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

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

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

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

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

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

A. As I explained above, Calpine acknowledges that many of the terms and conditions of Calpine's July 3rd PPA-acquisition proposal remain to be negotiated and, in Calpine's view, are "subject to certain adjustments." (Thornton Direct Test., p. 8, lines 9-10). This includes the terms for the actual

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

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

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

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

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

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

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

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

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

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

Finally, [redacted] are based on DEF's ability to exercise the "escape clause" at the end of year two of the PPA (or in 2016). If the PPA

were to run the full 5-year period, the alternative would be significantly worse in CPVRR impact compared to proceeding with the Suwannee Simple Cycle Project now.

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

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

DEF has no intention of entering into a long-term PPA for the Calpine plant capacity with an offer to acquire the plant available at the end of that period. DEF knows that PPA is not economic for DEF's customers. The intent of the PPA, again, is to get to the plant acquisition value, if any, and to obtain that value for DEF's customers by obtaining FERC approval for the acquisition as quickly as possible. Mr. Thornton makes clear he understood this was the intent of the deal when he describes the "escape" clause as a means of protecting DEF in the event that FERC denied DEF's application "for approval

of the acquisition." (Thornton Direct Test., p. 9, lines 3-6). Dr. Hunger does not specifically opine on whether FERC would or would not approve this PPA, one in which the parties specifically structured it to evade the FERC market screen issues associated with the straight-forward acquisition of the plant.

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

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

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

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

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

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

A. My understanding is that the Commission will determine:

(i) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for electric system reliability and integrity;

(ii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for adequate electricity at a reasonable cost;

(iii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for fuel diversity and fuel supply reliability;

(iv) Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to DEF that might mitigate the need for the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project;

(v) Are the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017 the most cost-effective alternative available to meet the needs of DEF and its customers; and

(vi) Did DEF reasonably evaluate all alternative scenarios for cost effectively meeting the needs of its customers over the relevant planning horizon.

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

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

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

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

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

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

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

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

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

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

The apparent position of NRG and Calpine with respect to the Hines Chillers Power Uprate Project is consistent with my direct testimony and exhibits in this docket. As I explained there, the addition of the Hines Chillers Power Uprate Project to every generation capacity resource proposal made every proposal more economically favorable for DEF's customers, and

therefore, our evaluation of the generation capacity resource proposals to meet DEF's need prior to 2018 included the Hines Chillers Power Uprate Project in every generation resource option. (Borsch Direct Test., p. 40, lines 17-23, p. 41, lines 1-3 and Exhibit No. ___ (BMHB-8). NRG and Calpine witnesses do not dispute this fact; in fact they both suggest the Hines Chillers Power Uprate Project as an alternative resource in addition to their generation capacity proposals, and the Calpine simplistic cost analysis supports the economic value of this Project for DEF's customers.

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

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

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

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

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

Mr. Hibbard, Mr. Thornton, and Mr. Pollock also criticize DEF's evaluation because they claim qualitative factors favor the Calpine plant or the NRG plant, respectively, rather than the Company's self-build generation projects to meet DEF's generation capacity need prior to 2018. In sum, they claim that, unlike the Company's self-build generation projects, the Calpine plant, or the NRG plant as the case may be, provides DEF customers price

certainty, in-service date certainty, operating condition certainty and flexibility, and, in the case of the Calpine plant, better emissions because it is an existing combined cycle unit. (Hibbard Direct Test., p. 6, lines 6-23, p. 7, lines 1-8, p. 34, lines 20-23, pp. 35-36; Thornton Direct Test., p. 10, lines 13-23, pp. 11-13; Pollock Direct Test., p. 9, lines 11-22, pp. 10-11). These witnesses overstate the benefits and ignore the uncertainties associated with the Calpine plant or NRG plant, and the proposals to sell the plants to DEF.

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

NRG witness Mr. Pollock also criticizes DEF's evaluation while steadfastly maintaining that one aspect of DEF's evaluation demonstrates that the NRG initial plant acquisition proposal is more cost effective than the Company's self-build generation projects. I will demonstrate that he cannot "pick and choose" what he likes from the evaluation and discard the rest of the

evaluation and explain why his recommendation based on part of that evaluation is simply wrong. In part this involves an explanation why his and NRG witness Mr. Dauer's assumptions that DEF can simply buy gas for the NRG plant the way NRG has done so as a merchant plant in the past fail to recognize DEF's obligation to reliably deliver power to customers during all hours, every day on its system. I will also demonstrate that Mr. Pollock fails to understand DEF's evaluation of the generation capacity resource options to meet DEF's need prior to 2018.

A. DEF'S GENERATION RESOURCE ALTERNATIVE EVALUATION.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mr. Hibbard acknowledges that this information regarding the economic dispatch of the generation resource option on DEF's generation system is the "key difference" between the LCOE analysis and a production cost model and that "production cost modeling can provide important insights and perspectives on resource operations and utilization over time, and on the likely value of resources on the system from an energy benefit perspective." (Hibbard Direct Test., p. 21, lines 11-14, lines 19-20). Mr. Hibbard simply criticizes the Strategist production cost model that DEF used only to identify the optimal resource plans for each alternative evaluated, ignores the Ventyx EPM hourly production cost model that DEF did use to obtain the admittedly "important

insights and perspectives on resource operations and utilization over time" and "likely value" of resources from an "energy benefit perspective," and instead testifies that DEF should have used the LCOE analysis that provides none of these benefits.

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

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

All of Mr. Hibbard's specific criticisms about the Strategist model --- beyond his vague claims that it is "opaque," "lacks transparency," and a "black box," which all mean the same thing (and with which I disagree) --- relate to the fact that the Strategist model is <u>not</u> an hourly production cost model. (Hibbard Direct Test., p. 22, lines 11-23, p. 23, lines 1-12). As I explained above, he does not know or he chooses to ignore that DEF also used the EPM

hourly production cost model in its evaluation. Nowhere in his testimony does Mr. Hibbard criticize the EPM hourly production model – he in fact says DEF should use it --- nor does he criticize DEF's use of the EPM hourly production model in its evaluation of the generation resource options, including Calpine's proposal, to meet DEF's need prior to 2018.

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

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

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

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

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

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

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

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

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

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

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

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

the Company's self-build peaking generation resource is much more cost effective than the Calpine plant.

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

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

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

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

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

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

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

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

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

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

circumstances of this Petition, DEF accepts the fact that it will be bound by the cost estimate of its self-build projects unless DEF can demonstrate that any cost increase was prudent and point to specific reasons to justify the increase.

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

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

In sum, despite the fact that the Calpine and NRG plants currently exist, there remain unknown terms and conditions associated with their final and best offers for those existing plants that make it clear that the claimed price and operational performance certainty that the Calpine and NRG witnesses

tout simply do not exist. There is no reason to believe that these unknown terms and conditions associated with their final and best offers are qualitatively less risky to the Company than completing the construction of a standard CT plant much like Duke Energy has done many times before.

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

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

A. NRG witness Mr. Pollock and Calpine witness Mr. Hibbard to a lesser degree criticize DEF's load forecast and resource plan to meet that load in their direct testimony. (Hibbard Direct Test., p. 42, lines 21-22, p. 43; Pollock Direct Test., p. 21, lines 11-16, pp. 22-23). NRG and Calpine filed this direct testimony in this Docket and in Docket 140110-EI, which involves DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant in 2018. While unclear, NRG witness Mr. Pollock and Calpine witness Mr. Hibbard in part of their direct testimony appear to be addressing DEF's need in 2018 and beyond, and, as a result, I have filed rebuttal testimony in Docket 140110-EI addressing this part of their direct testimony. Indeed, one reason I am unclear if these witnesses intended to direct this part of their testimony to DEF's need prior to 2018 is that they both claim that DEF should have selected their acquisition proposals and buying their existing plants to add

generation capacity rather than building new generation capacity still does not cure any claimed errors or uncertainty in DEF's load forecast. To the extent that Mr. Pollock or Mr. Hibbard are asserting these arguments in this Docket, I am providing the same rebuttal testimony to these arguments below that I provided in Docket No. 140110-EI in this Docket.

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

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

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

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

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

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

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

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

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

Additionally, DEF is projecting an increase in retail load from 2013 to 2014 as the Florida economy continues to improve and DEF continues to add customers. This projected increase in retail demand from 2013 is only 200MW greater than the increase in retail load DEF actually experienced from 2012 to 2013 as the Florida economy was just starting to improve after the recession

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

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

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

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

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

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

A. No. He in fact said there was nothing wrong with the Company's load forecast or the timing of its resource additions and retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). That must mean Mr. Hibbard finds nothing

wrong with the timing of the Suwannee Simple Cycle Project, the Hines Chillers Power Uprate Project, or the Citrus County Combined Cycle Power Plant.

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

Mr. Hibbard also notes that the "best" forecasts -- which include the Company's load forecasts -- have proven to be accurate to within 1 to 3 percent a year. (Hibbard Direct Test., p. 43, lines 12-16). DEF agrees that it has a demonstrated record of load forecast accuracy. Mr. Hibbard incorrectly concludes, however, that the minor deviations in the accuracy of the annual utility load forecasts can be compounded over several years, thus, leading to significant variations in actual demand. Mr. Hibbard ignores the fact that

utilities, including DEF, update their load forecasts regularly, including each year in the utility TYSP. If reasons exist to deviate from prior year forecasts, the load forecasts will be revised, and therefore, there is no statistical or reasonable basis to conclude that prior year deviations in load forecast accuracy can simply be summed up or compounded to determine the overall accuracy of the utility's load forecast. Exhibit No. ___ (BMHB-20) to my rebuttal testimony shows DEF's summer load forecasts over the last six years. This Exhibit shows that DEF updates its load forecast to anticipate the duration and recovery from the recession as well as other trends in expected demand.

In sum, then, his apparent contention that the Commission should simply depart from the assumptions in the Company's load forecasts and the Company's planned generation capacity additions to meet that projected load in DEF's resource plan because actual load conditions in the future may deviate from the assumed load conditions is unprincipled resource planning. The same assertion could be made to justify any deviation anyone wants to make from every single utility load forecast and resource plan because no forecast is absolutely accurate and actual conditions will always deviate to some degree from forecasted conditions. Despite the fact that actual load may be different from what DEF projects it to be DEF must still plan to meet that future load based on reasonable assumptions about future load conditions and resources to meet that load. That is the very nature of DEF's IRP process that is presented to the Commission each year in the utility TYSP and

reviewed by the Commission to determine if it is suitable for planning purposes. Mr. Hibbard has not identified any error in that IRP process or any principled resource planning reason for the Commission to deviate from the Company's conclusions based on that IRP process.

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

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

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

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

A. No, it is not. NRG's final and best offer is included as Exhibit No. ___ (BMHB-14) and the Company's evaluation of the NRG final and best offer is included

as Exhibit No. ___ (BMHB-15) to my rebuttal testimony. I address NRG's final and best offer in my rebuttal testimony above.

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

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

A. NRG witness Mr. Pollock at first focuses solely on part of DEF's economic analysis, its initial detailed economic analysis, and claims that this analysis demonstrates that the NRG Acquisition 1 proposal was the most cost effective generation capacity resource to meet DEF's need prior to 2018. (Pollock Direct Test., p. 8, lines 7-17). DEF's initial detailed economic analysis did show that the NRG Acquisition 1 proposal was marginally more cost effective than the Company's Suwannee Simple Cycle Project, but essentially

equivalent on a CPVRR basis over the 30-year study period. (Borsch Direct Test., p. 40, lines 4-15; Exhibit No. ___ (BMHB-8)).

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

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

A. No. Despite contending that the NRG Acquisition 1 proposal is the most cost effective option based solely on DEF's initial detailed economic analysis, NRG witness Mr. Pollock agrees that the NRG Acquisition 1 proposal should not be selected simply because it is less expensive over the 30-year period than other resource options in the Company's initial detailed economic analysis. (Pollock Direct Test., p. 11, lines 8-11). He concedes the "cost-effectiveness analysis should not be the sole deciding factor" and that "the Commission should use qualitative criteria in addition to the quantitative cost-effectiveness

analysis to determine the resources best suited for meeting DEF's" need. (Pollock Direct Test., p. 11, lines 17-18, lines 23-24). Mr. Pollock ignores, however, most of the qualitative factors that led DEF not to select the NRG Acquisition 1 proposal, many of which DEF asked NRG to address in its final and best offer. These factors are listed on page 47 of my direct testimony.

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

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

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

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

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

Mr. Dauer argues that NRG has managed to obtain gas on a non-firm or spot market basis, at an unspecified price, when NRG needed it to meet the

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

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

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

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

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

In addition, while the cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the

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

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

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

VI. CONCLUSION.

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

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

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

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

Calpine and NRG both submitted final and best offers after DEF filed its Petition and direct testimony and exhibits in this Docket because they obviously recognized their initial generation capacity proposals proved to be less cost effective than the Suwannee Simple Cycle Project. These proposals moved closer to the cost effectiveness of the Suwannee Simple Cycle Project,

but they still were not more cost effective than that Project to meet DEF's need for generation capacity in the summer of 2016.

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

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

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

resource to meet DEF's peaking generation capacity needs commencing in the summer of 2016.

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

Q. Does this conclude your rebuttal testimony?

A. Yes.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

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

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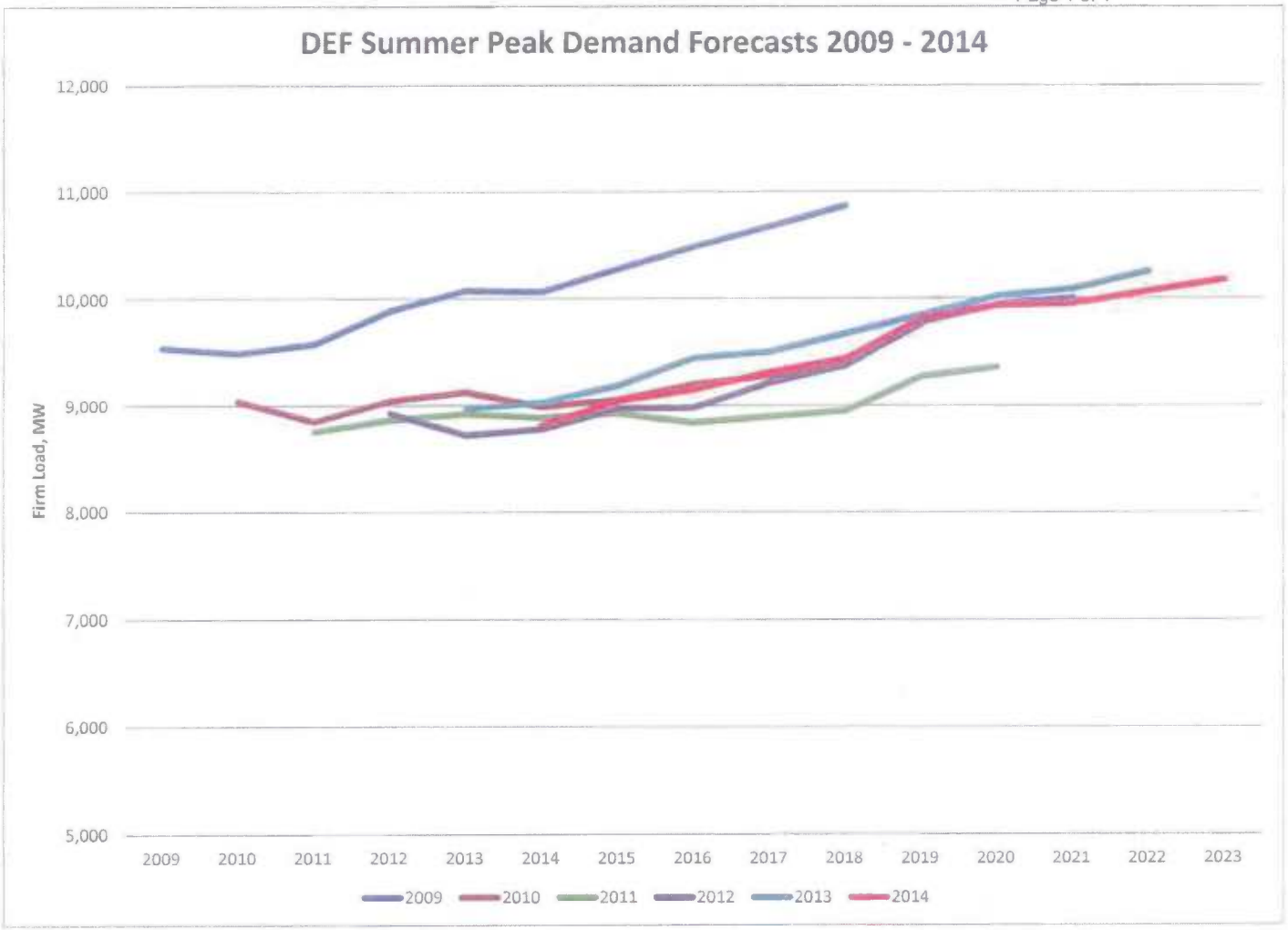

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF JULIE SOLOMON

ON BEHALF OF DUKE ENERGY FLORIDA, INC.

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

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

REBUTTAL TESTIMONY OF JULIE SOLOMON

I. INTRODUCTION.

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

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

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

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

A. No.

II. SUMMARY OF REBUTTAL TESTIMONY.

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

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

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

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

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

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

Fourth, Dr. Morris raises two issues, distinct from the basic scenario of a long-term PPA followed by an acquisition. One, he seems to argue that the base case (pre-transaction) should assume that DEF has some other additional generation under its control before it acquires additional generation, because this is "the most likely state of competition" without DEF acquiring the Osceola facility. Generally this implies that I understated the amount of Available Economic Capacity that DEF would have pre-transaction before making the decision about what new capacity to add. As a result, when DEF adds new capacity – whether Osceola or something else – the post-transaction

market concentration will be identical, or near-identical, to the pre-transaction market concentration such that the HHI change is zero and FERC will approve the transaction. As a general proposition, this argument appears to simply turn the FERC approach on its head – it would suggest for any utility seeking new generation, its status quo already has some form of additional generation in the mix – and I am not aware of such a premise in this form being accepted by FERC. More specifically, Dr. Morris further posits that, in the absence of a deal with DEF, NRG would either contract or sell its plant to another Florida utility or, alternatively, dismantle it and move it outside of Florida, and my analysis should take that into consideration. This approach leads to an analysis that has DEF building new generation and NRG exiting the market in the pre-transaction scenario as compared to a post-transaction scenario in which DEF acquires Osceola. This hypothetical appears, at best, purely theoretical and, at worst, speculative, as Dr. Morris has not presented any evidence in support of these outcomes (nor am I aware of any NRG witness providing such evidence). Two, Dr. Morris argues that there are additional mitigation measures that FERC might accept, citing cost-based offers or temporary transfer of control if the market power concerns were short-lived. Dr. Morris appropriately describes these as hypothetical, and, as noted, there is no firm proposal by NRG underpinning this hypothesis.

Q. How is the remainder of your testimony organized?

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

II. RESPONSE TO DR. HUNGER.

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

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

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

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

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

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

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

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

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

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

was designed specifically to avoid an appearance of market power under section 203, FERC could decide to take that factor into consideration in evaluating the application.

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

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

of capacity and energy into the DEF BAA, there still could be a change in generation MWs controlled in DEF, as shown in columns (4)-(5) of the table below.

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

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

While I have not conducted such an analysis, I note that there are many variables affecting the analysis – for example, how much is transmission increased from TECO to DEF, what is the effect on overall import capability into DEF, timing of the changes, etc. If such changes are anticipated, FERC likely would require an analysis that demonstrates

a lack of horizontal market power concerns, potentially as part of the original application or a later compliance filing.

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

III. RESPONSE TO DR. MORRIS.

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

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

Dr. Morris also notes that I have not considered a case in which DEF acquires the Osceola facility relative to a scenario in which DEF builds its own generation and NRG dismantles and moves the Osceola facility from the DEF BAA. (Morris 11:7-10) At the time of my Direct Testimony, I had no information that there was a plan for NRG to

move its facility if it was not acquired by DEF, nor am I aware of any facts to support this hypothetical at the present time, other than Dr. Morris' assertion that "it appears likely that NRG would move the combustion turbines to another location" and that it "appears to be an economic alternative for NRG." (Morris 16:15-21 and 17:1) If Dr. Morris' hypothetical stands up to scrutiny by FERC – which would require far more factual underpinning than presented here – Dr. Morris' analysis in Exhibit No.__ (JRM-3) still suffers from the comparison of a hypothetical pre-transaction scenario to a post-transaction acquisition of Osceola. Whereas, typically, a pre-transaction scenario reflects the status quo, here Dr. Morris' pre-transaction scenario posits a hypothetical, arguably speculative, scenario.

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

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

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

by Mr. Borsch. If DEF turns around and "sheds" control over that generation, it may not be able to meet such requirements.

IV. CONCLUSION.

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

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

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

Third, I am not convinced that Dr. Morris' alternative hypothetical wherein NRG is assumed to be "moving" the Osceola plant out of DEF, will qualify as an acceptable base case scenario in a FERC application. The basic premise of this hypothetical is to assume in the pre-transaction, status quo scenario that (i) DEF will buy or build

something; and (ii) NRG will move Osceola out of the market. There would have to be evidence to support the second assumption. And, the first assumption, fully separable from what NRG might do with Osceola, implies that FERC could find that the screens are passed in virtually every instance in which a utility is seeking to buy a new generating plant rather than build new generation. I am unaware of any precedent supporting this notion.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

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

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

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

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

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

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

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

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

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

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

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

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CERTIFICATE OF SERVICE

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

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

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

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

Docket No. 140111-EI
Duke Energy Florida
Corrected Exhibit No. ____ (BMHB-3)
Page 1 of 1

DEF's Near Term Summer And Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,8 70	8,812	39,801
2015	9,133	9,042	40,490
2016	9,370	9,149	41,098
2017	9,298	9,307	41,375

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Duke Energy Florida
Corrected Exhibit No. ____ (BMHB-8)
Page 1 of 1

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

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

Docket No. 140111-EI
Duke Energy Florida
Corrected Exhibit No. _____ (BMHB-10)
Page 1 of 1

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

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

Docket No. 140111-EI
Duke Energy Florida
Corrected Exhibit No. ____ (BMHB-11)
Page 1 of 1

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

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

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

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

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

Q. Why did FERC adopt the Competitive Analysis Screen?

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

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 17
PARTY: DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-3

DOCKET NO. _____
DUKE ENERGY FLORIDA
EXHIBIT NO. _____ (BMHB-4)
PAGE 1 OF 1

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 18
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF) (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch

19

DEF's Responses to Staff's First Set of Interrogatories (Nos. 2-5, 6 (CONFIDENTIAL), 11, 13, and 20-30)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 19
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's First Set of Interrogatories (Nos. 2-5, 6

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI SERVED: MARCH 25, 2015

REDACTED

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES NOS. (1-30)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Set of Interrogatories (Nos. 1-30) as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's First Set of Interrogatories Nos. 1-30, filed on March 16, 2015, as if those objections were fully set forth herein.

INTERROGATORIES

2. Please describe DEF's current plan, including scheduling, for the retirement of existing generating units at the Suwannee location. In this context, please explain whether any units at the Suwannee location will be needed for voltage support if the Osprey Plant is acquired added to DEF's system.

RESPONSE:

The current schedule is for Suwannee Steam Generators G1 and G2 to retire May of 2017, and for the G3 to retire May of 2018. If the Osprey Plant is acquired DEF will continue to operate the existing Suwannee Peakers on a network voltage schedule as specified by the DEF system operator. This operation is needed and intended to provide voltage support to the DEF BAA whenever necessary whether or not the Osprey Plant is acquired.

150043 Hearing Exhibits 00003

3. Please identify and describe the expected in-service date and requisite increase in capacity, as well as increase in reserve margin, for the Hines Chillers Uprate Project.

RESPONSE:

The expected in-service date for the Hines Chillers Uprate Project is June 2016 for Hines 1, July 2016 for Hines 3, August 2016 for Hines 4, and February 2017 for Hines 2. The estimated increase in capacity is 219MW. This will increase the Reserve Margin in 2016 by 1.8% and by a cumulative 2.4% in 2017.

4. Please complete Table 1 for the following scenarios using the same forecast data used in the instant filing (2014 Ten-Year Site Plan) and the most recently available forecast data (six completed tables):

a) Neither Osprey nor Suwannee Projects are completed.

b) Osprey unit only integrated into system as planned.

c) Suwannee units only integrated into system as planned.

For each scenario, please identify and include the effects of any planned retirements of existing generation units, other unit additions (including Citrus County), as well as expiration of PPAs and any other changes to the DEF system that are currently anticipated.

Table 1			
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			

RESPONSE:

Please see tables below. The 2015 tables are consistent with the current draft of the 2015 TYSP.

Total Installed Capacities and Total Peak Demands are expressed as megawatts (MW) at the time of the summer peak for each year specified.

Note that the capacity and reserve margin for 2017 listed in the 2014 "Neither Osprey Nor Suwannee" table (the first scenario presented) differs from that shown in Exhibit BMHB-4 presented in the pre-filed testimony. This difference has to do with the assumed cases. In Exhibit BMHB-4, the underlying assumption is that the Osprey acquisition will be completed, thus it is assumed that Suwannee Unit 3 continues operation until the Spring of 2018. In the Table presented below, the 2014 assumptions are shown, i.e. that Suwannee Unit 3 retires in 2017 with (or without) the construction of the Suwannee Peaker Project. The case presented in the testimony is the more conservative case for determining DEF's 2017 need and reflects the expectation that Suwannee Unit 3 will be retired one year earlier in the case that Suwannee Peakers are available in 2017.

In the second table below, "2014 Osprey Only" there is a difference of 7 MW between the total installed capacity shown here and the total installed capacity for the same case in each of the years 2017, 2018 and 2019. This is due to an updated value for the losses across the TEC system to deliver the power to DEF during that period. DEF's current understanding, shown in this table, is that the losses are slightly less than stated in the Exhibit and thus the net DEF capacity is higher by 7 MW.

Table 1	2014 TYSP - Neither Osprey nor Suwannee Projects are completed		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	17.3%	10,914	9,307
2018	16.5%	10,994	9,439
2019	20.4%	11,814	9,813
2020	17.9%	11,709	9,935
2021	21.4%	12,077	9,952
2022	20.0%	12,077	10,067
2023	18.7%	12,077	10,172
2024	16.1%	11,932	10,277
2025	16.8%	12,118	10,374
2026	16.6%	12,201	10,464

Table 1	2014 TYSP - Osprey unit only integrated into system as planned		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	20.7%	11,229	9,307
2018	19.6%	11,288	9,439
2019	22.9%	12,058	9,813
2020	23.6%	12,284	9,935
2021	20.2%	11,959	9,952
2022	21.5%	12,232	10,067
2023	20.3%	12,232	10,172
2024	19.9%	12,320	10,277
2025	22.4%	12,693	10,374
2026	20.3%	12,589	10,464

Table 1	2014 TYSP - Suwannee unit only integrated into system as planned		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	20.7%	11,230	9,307
2018	19.8%	11,310	9,439
2019	23.6%	12,130	9,813
2020	21.0%	12,025	9,935
2021	24.5%	12,393	9,952
2022	23.1%	12,393	10,067
2023	21.8%	12,393	10,172
2024	19.2%	12,248	10,277
2025	19.9%	12,435	10,374
2026	19.6%	12,517	10,464

Table 1	2015 TYSP - Neither Osprey nor Suwannee Projects are completed		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	18.0%	10,904	9,237
2018	17.3%	11,013	9,391
2019	19.8%	11,733	9,797
2020	16.8%	11,624	9,948
2021	18.1%	11,624	9,847
2022	16.3%	11,624	9,993
2023	14.7%	11,624	10,133
2024	14.2%	11,726	10,272
2025	16.3%	12,104	10,408
2026	14.3%	12,050	10,544

Table 1	2015 TYSP - Osprey unit only integrated into system as planned		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	20.7%	11,148	9,237
2018	19.9%	11,257	9,391
2019	22.3%	11,977	9,797
2020	22.6%	12,199	9,948
2021	23.9%	12,199	9,847
2022	22.1%	12,199	9,993
2023	20.4%	12,199	10,133
2024	19.8%	12,301	10,272
2025	21.8%	12,679	10,408
2026	19.7%	12,625	10,544

Table 1	2015 TYSP - Suwannee unit only integrated into system as planned		
Year	Reserve Margin (%)	Total Installed Capacity	Total Peak Demand (Summer)
2017	20.7%	11,149	9,237
2018	19.6%	11,229	9,391
2019	23.0%	12,049	9,797
2020	20.0%	11,940	9,948
2021	21.3%	11,940	9,847
2022	20.0%	11,990	9,993
2023	19.8%	12,143	10,133
2024	19.1%	12,236	10,272
2025	21.2%	12,614	10,408
2026	20.6%	12,713	10,544

5. Please describe future plans (beyond 2018) for the Suwannee Project, assuming the Osprey unit is acquired as planned.

RESPONSE:

Based on the completion of the Osprey acquisition and the completion of the planned transmission upgrades, DEF's next need as shown in the 2015 Ten Year Site Plan will be in 2024. While DEF continues to consider the Suwannee site a primary location for future generation development, the current advantageous attributes of the Suwannee Project in terms of transmission and natural gas availability may or may not be available for that future project. At the time DEF identifies a firm need for that future project, DEF will consider the conditions available for the Suwannee site and other alternative projects under consideration.

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6. Please provide the estimated "all-in" cost to have the full and complete output of the Osprey unit available on DEF's system. Please break the costs down into the following components: acquisition of the Osprey CC unit, performance of the necessary transmission system upgrades, and performance of all recommended and required maintenance activities. Please provide these estimates using sensitivities of +/- 10 percent for both maintenance and transmission costs, and include expected completion dates for the transmission upgrades and maintenance activities.

REDACTED

RESPONSE:

Currently the Osprey unit is under study through the DEF Generator Interconnection Request Study (GISR) process. The Study process will provide a detailed engineering estimate of ± 20% or ±10% per the customer's election. The complete Study process is expected to be complete by year-end, 2015. Until such time the best costs estimate and schedule is a Transmission Planning Estimate of $150 million with completion of associated transmission upgrades and associated maintenance activities by May 2020.

Below are costs for the plant acquisition, maintenance and integration costs.

	2017	2018
PLANT ACQUISITION	166,000	
TRANSACTION COSTS	[redacted]	
TOTAL ACQUISITION COST	[redacted]	
INVENTORY	[redacted]	
CAPITAL MAJOR MAINTENANCE COSTS	[redacted]	[redacted]
VOM	[redacted]	[redacted]
FOM		
O&M	[redacted]	[redacted]
INTEGRATION	[redacted]	[redacted]
PLANT CONDITION ALIGNMENT VOM	[redacted]	[redacted]
PLANT CONDITION ALIGNMENT CAPITAL	[redacted]	[redacted]
Integration and Upgrades	[redacted]	[redacted]

DEF did not perform a sensitivity on these costs. Simply applying the +/- 10% standard to the O&M costs would provide a range of [redacted] in 2018.

DEF plans to complete the initial major maintenance cycle for these units, along with alignments to the plant maintenance practices required to conform to DEF maintenance practices in 2017 and 2018.

As stated in the testimony of Mr. Scott and Mr. Borsch, DEF expects that the transmission upgrades necessary to fully integrate Osprey into the DEF transmission grid will be complete in 2020.

11. Please complete Table 2 for the following scenarios using the same forecast data used in the instant filing (2014 Ten-Year Site Plan), as well as using the most recently available forecast data (six completed tables):

a) Neither Osprey nor Suwannee Projects are completed.
b) Osprey unit only integrated into system as planned.
c) Suwannee units only integrated into system as planned.

Table 2			
	Annual Revenue Requirements for Fuel ($million)	Annual Revenue Requirements for Non-fuel O&M ($million)	Annual Impact on Residential Bill for 1,200 kWh/month ($)
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

RESPONSE:

DEF was not able to prepare an analysis of the "Neither Suwannee nor Osprey" case for either 2014 or 2015. Without either unit, the system would violate DEF's reserve margin criteria, so in order to produce a valid solution, DEF would need to postulate some alternate generation source, with hypothetical information, to meet the criteria. In this case, DEF has already identified Osprey, or in the alternate Suwannee, as the most cost effective generation to satisfy this reliability criteria, so it does not have any hypothetical information to complete a "Neither Suwannee nor Osprey" case.

Osprey 2014 – 11.b

	Annual Revenue Requirements for Fuel ($million, Nominal)	Annual Revenue Requirements for Non-fuel O&M ($million, Nominal)	Impact on Residential Bill for 1,200 kWh/month ($)
2015	1,824	539	0.07
2016	1,890	565	(0.08)
2017	2,091	644	(1.68)
2018	2,393	752	(1.13)
2019	2,591	858	(1.07)
2020	2,802	1,303	(1.18)
2021	2,909	1,331	2.44
2022	3,011	1,392	4.27
2023	3,125	1,490	3.43
2024	3,230	1,501	1.56
2025	3,365	1,488	(0.52)
2026	3,513	1,485	(0.81)
2027	3,651	1,597	(0.87)
2028	3,801	1,691	(0.74)
2029	3,915	1,779	(0.16)
2030	4,042	1,858	0.60
2031	4,216	1,969	(0.14)
2032	4,390	2,067	(0.14)
2033	4,561	2,176	(1.10)
2034	4,703	2,268	(0.76)
2035	4,852	2,371	(0.52)
2036	5,028	2,471	(1.24)
2037	5,180	2,562	0.12
2038	5,326	2,688	0.26
2039	5,467	2,805	0.49
2040	5,657	2,916	0.79
2041	5,830	3,074	1.13
2042	5,984	3,241	1.76
2043	6,163	3,384	2.08

Notes:

* Residential bill impact displayed as a differential from Suwannee CTs 2014. 1,200 kWh/month rate based on average residential price.

Suwannee CTs 2014 – 11.c

	Annual Revenue Requirements for Fuel ($million, Nominal)	Annual Revenue Requirements for Non-fuel O&M ($million, Nominal)	Impact on Residential Bill for 1,200 kWh/month ($)
2015	1,811	552	-
2016	1,876	574	-
2017	2,083	602	-
2018	2,382	727	-
2019	2,575	839	-
2020	2,781	1,281	-
2021	2,900	1,414	-
2022	3,016	1,523	-
2023	3,126	1,599	-
2024	3,245	1,536	-
2025	3,370	1,464	-
2026	3,515	1,453	-
2027	3,644	1,570	-
2028	3,792	1,670	-
2029	3,921	1,766	-
2030	4,063	1,858	-
2031	4,229	1,951	-
2032	4,397	2,054	-
2033	4,555	2,140	-
2034	4,717	2,226	-
2035	4,881	2,325	-
2036	5,027	2,427	-
2037	5,201	2,548	-
2038	5,341	2,685	-
2039	5,496	2,799	-
2040	5,671	2,934	-
2041	5,840	3,108	-
2042	6,011	3,284	-
2043	6,192	3,438	-

Notes:
* Residential bill impact displayed as a differential from Suwannee CTs 2014. 1,200 kWh/month rate based on average residential price.

Based on agreement with Staff DEF will provide responses to subparts 11b and c for the 2015 data on April 1, 2015.

13. In its petition at page 14, paragraph 27, DEF stated that its "remaining need for additional generation capacity is now approximately 180 MW in the summer of 2017, growing to over 300 MW in the summer of 2018." Please describe any efforts made by DEF to determine the availability of an amount of generation through purchased power contracts sufficient to maintain the required reserve margin for the two-year period from 2016 to 2018.

RESPONSE:

Failure to complete the Osprey Plant acquisition or to build the Suwannee Peakers not only results in the need referenced in Question 13, but also in persistent needs beginning in 2020 (see response to Question 4) which result in the need for additional generation to be constructed in that timeframe. As explained in DEF's evaluations presented in Docket 140111-EI included in Exhibit BMHB-2, DEF evaluated purchase power contracts as alternatives to the opportunity to acquire the Osprey Plant, or to build the Suwannee Project and determined that there were no purchases available that would provide a more cost effective plan than either the Osprey acquisition or the Suwannee Project to meet DEF's need commencing prior to 2018. This evaluation supported the decision that, based on the term sheet offered DEF at the commencement of the hearing in Docket 140111-EI, the Osprey acquisition was the most cost effective alternative to meet DEF's need, subject only to the Osprey Plant due diligence and the agreement to terms of an asset purchase agreement. As a result of this agreement to terms for the Osprey Plant acquisition there was no further evaluation of alternatives to the Osprey Plant acquisition or, alternatively, the Suwannee Project to meet DEF's need commencing prior to 2018. The minor changes to the need in 2017 and 2018 did not materially change the need commencing prior to 2018 that was met by the Osprey Plant acquisition.

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20. If the 2015 forecasts are used to evaluate the cost effectiveness of the two proposed projects rather than the 2014 data, would the results be any different? If "yes", why? If "no", why not?

RESPONSE:

In general, use of the 2015 forecasts in an economic evaluation is expected to narrow the differential between the Osprey acquisition and the Suwannee Peaker project. The primary driver of this change is the change in the after tax discount rate which has risen from the 6.46% projected in 2013 and 2014 to 6.95% in 2015. Because ownership of the Osprey facility generates benefits over the life of the project projected through 2043, the higher 2015 discount rate would lower the expected favorability of the Osprey plant by approximately $27M if viewed in isolation without considering other factors.

The 2015 natural gas forecast shows slightly lower prices in the near term (2015 – 2020); comparable prices during the decade of the 2020's; and higher prices beyond 2027. In most years, the differentials are small percentages of the total price. While lower natural gas prices generally favor the Suwannee Peaker Project, the fact that later prices are expected to rise above the 2014 projections indicates that the long run value of the Osprey Plant selection will be reinforced.

The changes in the 2015 load forecast are shown in the response to Question 4. In the near term, lower loads are projected, but continuing increases in Florida population drive higher expected peak load over the longer term such that the peak loads are expected to be approximately equal in 2025 in each forecast, and higher in the period beyond. While lower projected peak firm demands would generally favor the Suwannee selection, an examination of the two resource plans indicates that the near term change has not been sufficient to change the mix of resources in each plan, thus minimizing any impact on the total capital in each plan. Changes to the forecast beyond 2025 have a minimal impact on the differential since the two plans are identical in resource mix beyond that point.

21. For the purposes of the following requests, please refer to DEF's 2014 TYSP and 2015 TYSP as referenced in the direct testimony of DEF Witness Borsch, page 31.

a. Please discuss the reasons, if applicable, for any deviation greater than 200 MW in DEF's 2014 forecasted Net Firm Demand and 2014 actual (2015 TYSP) Net Firm Demand for both summer (Schedule 3.1) and winter (Schedule 3.2).

RESPONSE:

The differences in forecasted and actual 2014 net demand are 274MW in Schedule 3.1 (Summer Peak) and 1,388MW in Schedule 3.2 (Winter Peak). The actual values are below the projected values from the DEF TYSP 2014. The reasons for these differences include the following:

Summer

Weather: The summer 2014 peak hour weather condition was +0.1 degree warmer than the normal value resulting in an actual peak +8.6MW higher due to weather.

Customers: The number of Retail customers on the DEF system (excluding Street Lighting) were +0.1% from the projection resulting in an additional 12.6 MW to the actual peak.

Wholesale: The summer peak wholesale projection deviated from projection by +3MW or 0.4%.

Economy: The main driver of the variance is prolonged economic weakness which continued to depress the actual 2014 summer peak. While DEF has observed a decline in "active, but vacant" residential accounts from the peak in 2012, this figure remains over 18% above the pre-recession 2005-06 average. DEF's seasonal peak modeling methodology incorporates a "recession indicator" variable to measure the recession's implicit impact on seasonal peak since the start of the recession. It statistically captured the decline in historical peak. The projected values for this variable were structured to capture an expected improvement to the Florida economy. The forecast incorporates a "feathered" decline of this particular variable's value over the next several years including 2014 as vacant homes fill up and business

returns to pre-recession levels. The pace of recovery has been slower than what was estimated which reflects a lag in the projected return to pre-recession economic activity levels that support the long term forecast.

Winter

Weather: Weather is the main driver of the difference in the Winter values. The winter 2013/2014 peak hour weather condition was +5.3 degrees warmer than normal value resulting in a difference between the forecast and actual peak that was 1,088MW lower due to milder weather.

Customers: The number of Retail customers on the DEF system (excluding Street Lighting) were +0.03% from the projection resulting in a +3.5 MW difference compared with the actual peak.

Wholesale: The winter peak wholesale projection deviated from forecast by -249MW or -27.8% as wholesale customers with firm capacity contracts with DEF elected to purchase energy available from the market.

Economy: For the Winter forecast, the remaining difference of roughly 50 MW is likely reflective of minor variations in the economic indicators used.

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b. Please discuss the reasons, if applicable, for any deviation greater than 200 MW in DEF's 2015-2022 forecasted summer and winter Net Firm Demand (Schedules 3.1 & 3.2) between the Company's 2014 and 2015 TYSPs.

RESPONSE:

A review of the two identified TYSP projections in Question 21b., show that deviations greater than 200 MW occurred in the Winter projections for the three seasonal peaks occurring 2014-15, 2015-16 and 2016-17.

With normal weather conditions, DEF will experience its annual peak in the Winter. Normal Winter peak weather forecasts are based on the weather conditions which occurred during the twenty Winter peaks from 1994-2013. The forecasted demands reflect a weighted average of the weather conditions in the two hours around the peak hour (67%) and the previous twenty-four hour period ending in the peak hour (33%). This weather derivation is found to best capture historical peak demand conditions. However, this twenty year historical sample period includes several "not so cold" conditions at time of winter peak as well as some more extreme conditions such as the 2010 winter. While the DEF methodology uses a twenty year average, an upward shift in the near term winter peak projection resulted from an adjustment in the recession indicator variable to address the potential for a colder-than-normal peak as economic activity returns to pre-recession levels.

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22. Please identify the dates when the 2014 and 2015 TYSP load forecasts were prepared, when the source data was obtained, and when final management approvals were complete. Explain the review process.

RESPONSE:

Please refer to Pages 2-14 – 2-24 of the DEF TYSP 2014 (Figure 2.1).

Both load forecasts were developed during the Fall in the year previous to the April 1st publication date. Completion dates typically occur near year end as final wholesale contract information is received. However, the 2015 TYSP forecast was not completed unit February 2015 as a result of additional time needed to incorporate new DSM Goals targets from the Efficiency and Conservation Docket, which was completed on December 16, 2014. The final forecast was approved by DEF management on February 9, 2015.

Source data was obtained with "vintage" dates described in each TYSP "General Assumptions" area of the respective document. Please refer to the DEF TYSP 2014, Chapter Two, and the attached excerpt of Chapter Two from the 2015 TYSP, which will be filed in its entirety on April 1, 2015.

The forecast review and approval process begins with the Lead Load Forecast Analyst presenting final results to the Director of Load Forecasting and Fundamentals. Topics include a review of economic & demographic and normal weather changes upon retail class energy sales, customer growth and monthly coincident peak demand. A review of all wholesale contracts (energy and peak projections) is performed as well. This review is typically conducted at year end for budget purposes and may not include certain final adjustments including yearend actual results of DSM accomplishments. Final adjustment are made between the DSM group, the Lead Load Forecast Analyst and reviewers on the IRP team. After completion of final adjustments, the Load Forecast is presented to the State President of the Florida jurisdiction for approval to be included in the Ten-Year Site Plan Document.

Please see documents bearing Bates Nos. 15LGBRA-STAFFROG1-22-000001 through 15LGBRA-STAFFROG1-22-000035.

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CHAPTER 2
FORECAST OF ELECTRIC POWER DEMAND
AND
ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). DEF's customer growth is expected to average 1.1 percent between 2015 and 2024, which is more than the ten-year historical average of 0.7 percent. County population growth rate projections from the University of Florida's Bureau of Economic and Business Research (BEBR) were incorporated into this projection. The severe financial crisis witnessed both nationwide and in Florida since 2007 has dampened the DEF historical ten-year growth rate significantly as total customer growth turned negative for a twenty-one month period during 2008, 2009 and 2010. Economic conditions going forward look more amenable to improved customer growth due to low mortgage rates, higher household formations and a large retiring baby-boomer population.

Net energy for load (NEL) dropped by an average 1.5 percent per year between 2005 and 2014 due primarily to the economic recession and the weak economic recovery that followed. Sales for Resale in 2014 were only 26% of their 2005 level. An improved economic environment (including improved migration population rates, construction activity, wage growth and consumer spending) is expected to drive the DEF service area forecast. The 2015 to 2024 period is expected to improve NEL by an average growth rate of 1.5 percent per year matching the rate of customer growth. Going forward, projected NEL growth continues to reflect the FPSC approved DSM energy savings targets.

Summer net firm demand declined an average 0.7 percent per year during the last ten years, mostly driven by lower wholesale load that was only 33% below the average of the previous nine summers. The projected ten year period summer net firm demand growth rate of 1.6 percent is primarily driven by higher population improving net firm retail demand and significantly less drag from the wholesale sector.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided:

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1	History and Forecast of Base Summer Peak Demand (MW)
3.2	History and Forecast of Base Winter Peak Demand (MW)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

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DUKE ENERGY FLORIDA

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
2005	3,427,860	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,505,058	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,531,483	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,727	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,937	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,813	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,633,620	2.491	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,681,835	2.493	18,508	1,477,164	12,529	11,718	163,671	71,594
2014	3,701,245	2.485	19,003	1,489,502	12,758	11,789	165,899	71,060
2015	3,760,148	2.471	19,388	1,521,581	12,742	11,974	169,462	70,659
2016	3,794,503	2.457	19,521	1,544,672	12,638	12,095	172,049	70,300
2017	3,836,847	2.446	19,898	1,568,777	12,684	12,334	174,744	70,583
2018	3,882,632	2.437	20,068	1,593,408	12,594	12,443	177,495	70,103
2019	3,936,092	2.433	20,254	1,618,125	12,517	12,548	180,253	69,613
2020	3,991,020	2.430	20,489	1,642,516	12,474	12,758	182,973	69,726
2021	4,044,019	2.427	20,717	1,666,272	12,433	12,910	185,622	69,550
2022	4,095,523	2.424	20,950	1,689,354	12,401	13,071	188,195	69,455
2023	4,145,499	2.422	21,210	1,711,831	12,390	13,239	190,700	69,423
2024	4,195,255	2.420	21,453	1,733,788	12,373	13,396	193,146	69,357

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DUKE ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		INDUSTRIAL					
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
2005	4,140	2,703	1,531,632	0	27	3,171	39,176
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	3,819	2,668	1,431,409	0	26	3,341	39,282
2008	3,786	2,587	1,463,471	0	26	3,276	38,555
2009	3,285	2,487	1,320,869	0	26	3,230	37,824
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,370	1,352,743	0	25	3,159	36,616
2014	3,267	2,328	1,403,351	0	25	3,157	37,240
2015	3,350	2,251	1,488,227	0	24	3,202	37,938
2016	3,355	2,228	1,505,835	0	24	3,214	38,209
2017	3,356	2,208	1,519,928	0	24	3,234	38,846
2018	3,316	2,189	1,514,847	0	24	3,247	39,098
2019	3,416	2,172	1,572,744	0	23	3,255	39,496
2020	3,450	2,157	1,599,444	0	23	3,278	39,998
2021	3,395	2,143	1,584,228	0	23	3,304	40,349
2022	3,340	2,131	1,567,339	0	22	3,335	40,718
2023	3,282	2,120	1,548,113	0	22	3,362	41,115
2024	3,223	2,110	1,527,488	0	22	3,388	41,482

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DUKE ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
2005	5,195	2,507	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	5,598	2,753	47,633	24,010	1,632,368
2008	6,619	2,484	47,658	24,738	1,638,935
2009	3,696	2,604	44,124	24,993	1,630,195
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	13,548	1,656,753
2014	1,333	2,402	40,975	25,725	1,683,454
2015	955	2,533	41,426	26,121	1,719,415
2016	1,107	2,631	41,947	26,480	1,745,429
2017	1,230	2,289	42,365	26,863	1,772,592
2018	1,234	2,447	42,779	27,261	1,800,353
2019	1,408	2,668	43,572	27,666	1,828,216
2020	1,539	2,532	44,069	28,071	1,855,717
2021	1,529	2,444	44,322	28,471	1,882,508
2022	1,530	2,433	44,681	28,859	1,908,539
2023	1,530	2,435	45,080	29,238	1,933,889
2024	1,534	2,528	45,544	29,607	1,958,651

15LGBRA-STAFFROG1-22-000005

150043 Hearing Exhibits 00025

DUKE ENERGY FLORIDA

SCHEDULE 3.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
2005	10,350	1,118	9,232	448	310	203	38	166	110	9,074
2006	10,147	1,257	8,890	329	307	222	37	170	66	9,016
2007	10,931	1,544	9,387	334	291	239	45	177	110	9,735
2008	10,592	1,512	9,080	500	284	255	66	192	110	9,186
2009	10,853	1,618	9,235	262	291	271	84	211	110	9,624
2010	10,242	1,272	8,970	271	304	298	96	234	110	8,929
2011	9,972	934	9,038	227	317	329	97	256	110	8,636
2012	9,788	1080	8,708	262	328	358	98	280	124	8,337
2013	9,581	581	9,000	317	341	382	101	298	124	8,017
2014	10,067	807	9,260	232	355	404	108	313	132	8,523
2015	10,532	812	9,720	247	363	421	113	324	132	8,932
2016	10,619	647	9,972	247	369	436	118	331	132	8,986
2017	10,905	751	10,154	252	375	449	122	338	132	9,237
2018	11,074	752	10,322	242	381	460	126	343	132	9,390
2019	11,528	1,004	10,524	266	387	468	130	348	132	9,797
2020	11,744	1,005	10,739	303	393	480	135	352	132	9,948
2021	11,667	755	10,912	304	399	491	139	355	132	9,847
2022	11,835	755	11,080	304	405	501	143	357	132	9,993
2023	11,996	755	11,241	304	411	510	148	358	132	10,133
2024	12,155	755	11,400	303	417	519	152	359	132	10,273

Historical Values (2005 - 2014):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2015 - 2024):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
2004/05	10,828	1,600	9,228	575	779	368	26	124	283	8,673
2005/06	10,695	1,467	9,228	298	762	409	26	125	239	8,835
2006/07	9,894	1,576	8,318	304	671	450	26	127	262	8,055
2007/08	10,962	1,828	9,134	234	763	483	34	133	278	9,036
2008/09	12,089	2,229	9,860	268	759	518	71	148	291	10,034
2009/10	13,694	2,189	11,505	246	651	563	80	163	322	11,670
2010/11	11,343	1,625	9,718	271	661	628	94	180	221	9,288
2011/12	9,721	905	8,816	186	643	686	96	203	206	7,701
2012/13	9,109	831	8,278	287	652	747	97	220	213	6,893
2013/14	9,467	646	8,821	257	654	785	101	229	219	7,222
FORECAST:										
2014/15	11,793	1,381	10,411	224	668	820	109	238	247	9,487
2015/16	11,969	1,344	10,625	224	679	856	113	238	249	9,609
2016/17	11,975	1,197	10,778	229	690	890	118	239	251	9,558
2017/18	12,119	1,198	10,921	219	701	919	122	240	252	9,666
2018/19	12,296	1,198	11,098	241	712	943	126	240	254	9,779
2019/20	12,735	1,448	11,287	275	723	972	130	241	256	10,138
2020/21	12,735	1,299	11,436	276	734	999	135	241	257	10,093
2021/22	12,881	1,299	11,582	276	745	1,025	139	241	259	10,196
2022/23	13,024	1,299	11,725	276	756	1,049	143	242	260	10,298
2023/24	13,161	1,299	11,862	275	767	1,072	147	242	262	10,396

Historical Values (2005 - 2014):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2015 - 2024):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

15LGBRA-STAFFROG1-22-000007

150043 Hearing Exhibits 00027

DUKE ENERGY FLORIDA

SCHEDULE 3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
2005	48,475	455	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,399	484	365	509	39,432	4,220	2,389	46,041	52.1
2007	49,310	511	387	779	39,282	5,598	2,753	47,633	52.3
2008	49,208	543	442	565	38,556	6,619	2,483	47,658	53.1
2009	45,978	583	492	779	37,824	3,696	2,604	44,124	44.5
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.0
2013	43,142	772	734	864	36,616	1,488	2,668	40,772	53.0
2014	43,442	812	791	864	37,240	1,333	2,402	40,975	50.7
)RECAST:									
2015	43,986	838	809	913	36,491	936	3,999	41,426	49.8
2016	44,549	861	825	916	36,948	974	4,025	41,947	49.7
2017	44,999	882	839	913	37,584	1,024	3,757	42,365	50.6
2018	45,443	899	852	913	38,073	795	3,911	42,779	50.5
2019	46,259	912	862	913	38,624	767	4,181	43,572	50.9
2020	46,777	921	871	916	39,350	1,046	3,673	44,069	49.5
2021	47,040	928	877	913	39,983	1,270	3,069	44,322	50.1
2022	47,406	931	881	913	40,404	1,243	3,034	44,681	50.0
2023	47,812	934	885	913	40,991	1,244	2,845	45,080	50.0
2024	48,283	935	888	916	41,469	1,244	2,831	45,544	49.9

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration.

** Load Factors for historical years are calculated using the actual winter peak demand except the 2004, 2007, 2012 - 2014 historical load factors which are based on the actual summer peak demand which became the annual peaks for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

DUKE ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2014		2015		2016	
	PEAK DEMAND	NEL	PEAK DEMAND	NEL	PEAK DEMAND	NEL
MONTH	MW	GWh	MW	GWh	MW	GWh
JANUARY	8,329	3,407	10,603	3,123	10,743	3,153
FEBRUARY	6,972	2,648	8,860	2,753	9,159	2,864
MARCH	5,203	2,977	8,005	2,958	8,042	2,949
APRIL	7,514	3,049	8,047	3,028	8,169	3,050
MAY	7,996	3,637	8,805	3,653	8,913	3,697
JUNE	8,608	3,877	9,356	3,963	9,322	4,017
JULY	8,049	4,166	9,412	4,210	9,397	4,268
AUGUST	9,218	4,379	9,655	4,313	9,720	4,356
SEPTEMBER	8,372	3,725	8,908	3,976	8,875	4,019
OCTOBER	8,031	3,333	8,302	3,496	8,272	3,558
NOVEMBER	6,862	2,807	7,093	2,868	7,065	2,911
DECEMBER	6,408	2,970	8,885	3,085	8,783	3,105
TOTAL		40,975		41,426		41,947

NOTE: Recorded Net Peak demands and System requirements include off-system wholesale contracts.

15LGBRA-STAFFROG1-22-000009

150043 Hearing Exhibits 00029

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. DEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one fuel source. Near term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth and natural gas generation costs reflect relatively attractive natural gas commodity pricing.

15LGBRA-STAFFROG1-22-000010

150043 Hearing Exhibits 00030

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,792	5,176	4,072	3,588	3,540	2,667	3,370	2,285	2,325	2,391	2,614	2,531
(3)	RESIDUAL	TOTAL	1,000 BBL	251	0	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	251	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	132	167	114	102	85	102	108	105	99	102	124	110
(9)		STEAM	1,000 BBL	55	55	47	56	51	45	37	56	61	54	59	50
(10)		CC	1,000 BBL	8	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	69	112	67	46	34	57	71	49	39	48	65	60
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	177,196	182,286	193,425	204,169	223,430	237,360	235,269	252,884	252,638	253,663	252,171	264,768
(14)		STEAM	1,000 MCF	23,404	32,855	28,164	27,199	25,797	19,345	19,223	15,624	16,277	16,315	16,346	15,770
(15)		CC	1,000 MCF	150,875	144,737	158,027	170,803	192,150	212,024	210,806	232,559	231,765	232,858	230,788	238,830
(16)		CT	1,000 MCF	2,917	4,694	7,234	6,168	5,482	5,991	5,241	4,701	4,595	4,490	5,037	10,167
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	N/A	N/A	24,407	27,509	12,380	9,649	2,379	3,861	4,367	3,844	4,615	4,983
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	N/A	N/A	9,430	7,693	6,801	7,973	6,245	4,283	4,452	4,747	4,968	2,019
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	N/A	N/A	184	87	0	0	0	0	0	0	0	0

150043 Hearing Exhibits 00031

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,409	1,755	2,890	2,938	636	744	583	400	415	442	464	183
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,577	11,760	8,583	7,386	7,251	5,422	7,125	4,653	4,760	4,910	5,374	5,214
(4)	RESIDUAL	TOTAL	GWh	127	0	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	127	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	93	38	27	18	13	23	28	20	16	19	25	24
(10)		STEAM	GWh	58	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	7	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	28	38	27	18	13	23	28	20	16	19	25	24
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,061	22,962	25,477	26,991	29,696	32,177	32,351	35,119	35,044	35,213	34,977	36,559
(15)		STEAM	GWh	1,951	2,931	2,339	2,216	2,057	1,407	1,458	1,048	1,100	1,126	1,117	1,064
(16)		CC	GWh	20,893	19,674	22,486	24,208	27,122	30,227	30,420	33,615	33,496	33,654	33,381	34,541
(17)		CT	GWh	217	357	652	567	516	543	473	456	448	433	479	954
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,886	1,654	1,570	1,684	1,746	1,745	1,742	1,747	1,745	1,743	1,662	734
	RENEWABLES OTHER		GWh	1,132	23	0	0	0	0	0	0	0	0	0	0
	RENEWABLES MSW				708	578	569	605	605	605	607	605	605	605	607
	RENEWABLES BIOMASS				196	656	663	692	692	692	694	692	692	692	694
	RENEWABLES SOLAR				0	3	21	40	59	121	305	451	532	653	851
	IMPORT FROM OUT OF STATE		GWh	1,546	1,958	1,641	1,677	1,685	1,312	324	525	594	523	628	678
	EXPORT TO OUT OF STATE		GWh	-59	-79	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	40,772	40,975	41,426	41,947	42,365	42,779	43,572	44,069	44,322	44,681	45,080	45,543

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

150043 Hearing Exhibits 00032

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	ANNUAL FIRM INTERCHANGE 1/		%	3.8%	4.3%	7.0%	7.0%	1.5%	1.7%	1.3%	0.9%	0.9%	1.0%	1.0%	0.4%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	24.3%	28.7%	20.7%	17.6%	17.1%	12.7%	16.4%	10.6%	10.7%	11.0%	11.9%	11.4%
(4)	RESIDUAL	TOTAL	%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.3%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%
(10)		STEAM	%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	58.2%	56.0%	61.5%	64.3%	70.1%	75.2%	74.2%	79.7%	79.1%	78.8%	77.6%	80.3%
(15)		STEAM	%	5.3%	7.2%	5.6%	5.3%	4.9%	3.3%	3.3%	2.4%	2.5%	2.5%	2.5%	2.3%
(16)		CC	%	52.1%	48.0%	54.3%	57.7%	64.0%	70.7%	69.8%	76.3%	75.6%	75.3%	74.0%	75.8%
(17)		CT	%	0.9%	0.9%	1.6%	1.4%	1.2%	1.3%	1.1%	1.0%	1.0%	1.0%	1.1%	2.1%
(18)	OTHER 2/														
	QF PURCHASES		%	6.7%	4.0%	3.8%	4.0%	4.1%	4.1%	4.0%	4.0%	3.9%	3.9%	3.7%	1.6%
	RENEWABLES OTHER		%	2.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES MSW				1.7%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.3%
	RENEWABLES BIOMASS				0.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%
	RENEWABLES SOLAR				0.0%	0.0%	0.0%	0.1%	0.1%	0.3%	0.7%	1.0%	1.2%	1.4%	1.9%
	IMPORT FROM OUT OF STATE		%	3.8%	4.8%	4.0%	4.0%	4.0%	3.1%	0.7%	1.2%	1.3%	1.2%	1.4%	1.5%
	EXPORT TO OUT OF STATE		%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

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FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

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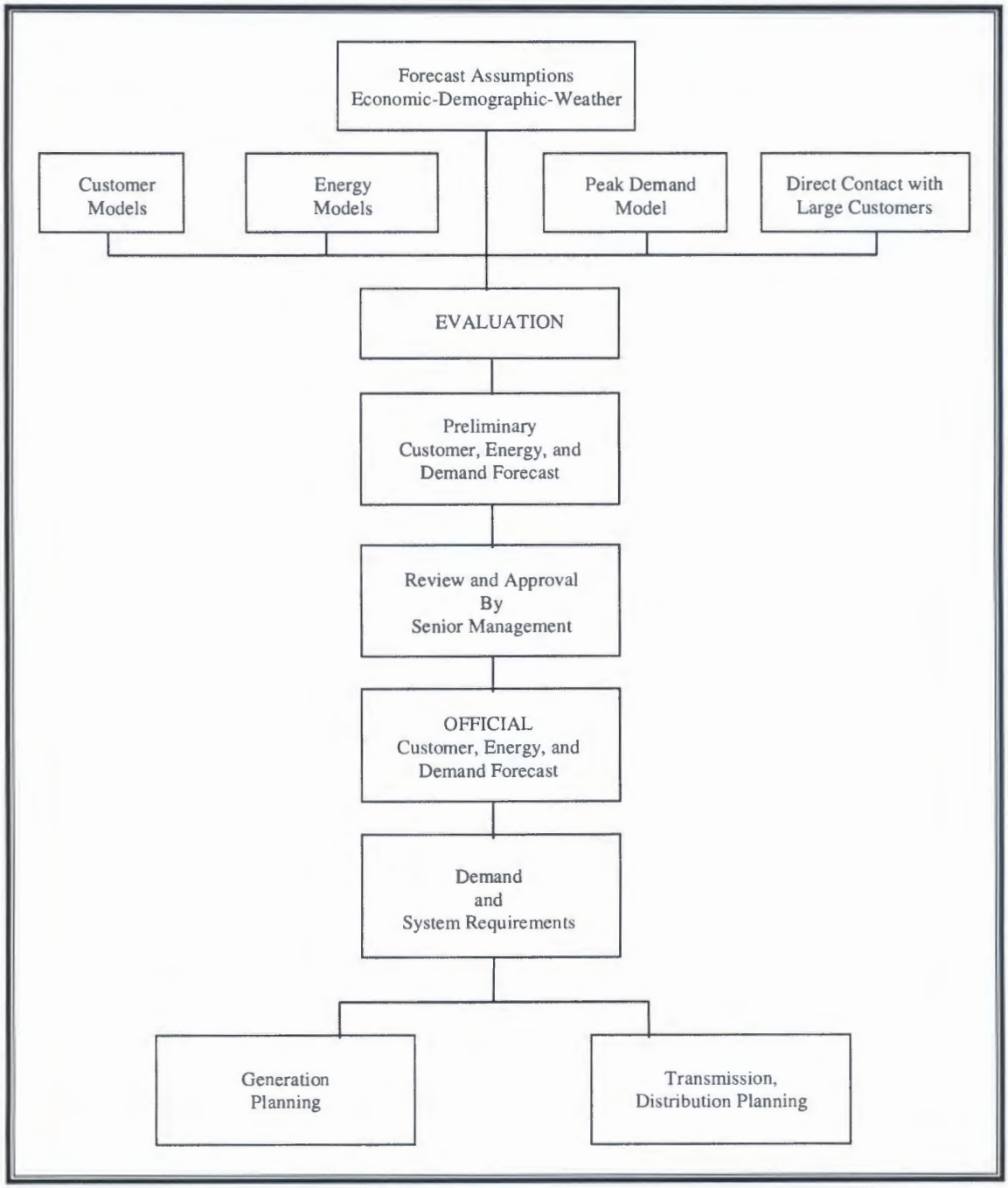
FIGURE 2.1

Customer, Energy, and Demand Forecast



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GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 10-year average of conditions at the St Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 10-year average of the billing cycle weighted monthly heating and cooling degree-days. The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the ten year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day values begin to accumulate. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the same three weather stations. The remaining non-seasonal peak months of the year may use less than 30 years if an historical monthly peak occurred due to unusual weather.

2. DEF customer forecast is based upon historical population estimates and produced by the BEBR at the University of Florida (as published in "Florida Population Studies", Bulletin No. 65 March 2014) and provides the basis for the 29 county population forecast used in the development of the DEF customer forecast. National and Florida economic projections produced by Moody's Analytics in their July 2014 forecast, along with EIA 2014 surveys of residential appliance saturation and average appliance efficiency levels provided the basis for development of the DEF energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Three major customers accounted for nearly 32 percent of the industrial class MWh sales in 2014. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward,

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global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. The DEF forecast calls for a continuation of the depressed level of annual electric energy consumption experienced in 2014 due to a mine shutdown brought about by the merger of two mining customers. Also, the current strength of U.S. Dollar makes all domestic production less price competitive at home and abroad. The forecast does account for one customer's intention to open a new mine later in this decade. A risk to this projection lies in the price of energy, which is a major cost in mining and producing phosphoric fertilizers.

4. DEF supplies load and energy service to wholesale customers on a "full" and "partial" requirement basis. Full requirements (FR) customers demand and energy are assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Chattahoochee, Mt. Dora and Williston. Partial requirements (PR) customers load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Reedy Creek Improvement District (RCID), Seminole Electric Cooperative, Inc. (SECI), and the cities of New Smyrna Beach and Homestead.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently FPSC approved DSM targets as stated in Docket No. 130200-EI .

7. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. DEF will supply the supplemental load of self-service cogeneration customers. While DEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place. FR

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customers are typically assumed to renew their contracts with DEF except those who have termination provisions and have given their notice to terminate. PR contracts are typically projected to terminate as terms reach their expiration date.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the Fall of 2014 as the nation's economy appeared to display stronger signs of growth. Most economic indicators pointed to significant year-over-year improvements. These included strong employment growth and declining unemployment, lower home foreclosures, moderately higher construction levels and much improved consumer confidence. Nationally, energy prices were declining, along with interest rates, and consumers were spending (and borrowing) again. What was not reported, however, were gains in median household incomes (after inflation) and improvement in the rate of homeownership. Both may be the result of a prolonged impact from the Great Recession where an oversupply of labor forced down wage rates, increased the number of lower paid part-time positions, damaged personal credit histories for many potential homebuyers and severely restricted mortgage credit compared to levels reached in the pre-financial crisis period.

In Florida, statewide job growth was among the highest nationally. In 2014, the State became the third most populous in the nation, according to the U.S. Census Bureau. Construction cranes could be seen again in almost every direction. Tourism levels have returned, boosting the vibrancy of the local economies. Public sector tax receipts have improved, allowing this sector to become a positive force on aggregate demand in the economy after many years in decline.

The DEF forecast incorporates the economic assumptions implied in the Moody's Analytics U.S. and Florida forecasts with some minor tempering to its short term optimism. This view suggests that the de-leveraging American consumer has begun to spend again, feeling more secure about the future. The newfound abundance of American energy supplies will improve tourism travel, both by air and car. Finally, low oil and natural gas prices, are expected to improve the country's competitive advantage in several manufacturing sectors. A tempering of this optimistic picture must be applied by recognizing the number of weak economies around the globe and the amount of excess capacity available to out-bid American producers in a strong USD World. Gains will come

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from service-related sectors in which the Florida economy does well. The State economy will benefit from more spending in health care and the retiring baby-boom generation. An improvement in the State's building products and infrastructure manufacturers has already begun. Throughout the ten year forecast horizon, risks and uncertainties are always recognized and handled on a "highest probability of outcome" basis. General rules of economic theory, namely, supply and demand equilibrium are maintained in the long run. This notion is applied to energy/commodity prices, currency levels, the housing market, wage rates, inflation and interest rates. Uncertainty surrounding international crises, such as wars or terrorist acts, are not explicitly designed into this projection. Thus, any situations of this variety will force a deviation from the forecast.

Also incorporated in this energy forecast is a projection of customer-owned solar photovoltaic generation and electric vehicle ownership. The net energy impact of both are expected to result in only marginal impacts to the forecasted energy growth.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, interruptible service and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Analytics and the University of Florida's

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BEBR. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. The incorporation of residential and commercial "end-use" energy have been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company's Market Research department and the Energy Information Agency (EIA), along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an easier explanation of usage levels and changes in weather-sensitivity over time. The "bundling" of 19 residential appliances into "heating", "cooling" and "other" end uses form the basis of equipment-oriented drivers that interact with typical exogenous factors such as real median household income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with households within DEF's 29-county service area. County level population projections for counties in which DEF serves residential customers are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. As in the residential sector, these variables are interacted with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating

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- Cooling
- Ventilation
- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the EIA's Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing

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employment interacted with the Florida industrial production index, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon. The projection of industrial accounts are expected to continue its historic decline. The decline in manufacturing nationwide, the increased competitiveness between the states, mergers between companies within the state, all have resulted in a continued decline in customer growth for this class.

Street Lighting

Electricity sales to the street and highway lighting class have remained flat for years but have declined of late. A continued decline is expected as improvements in lighting efficiency are projected. The number of accounts, which has dropped by more than one-third since 1995 due to most transferring to public authority ownership, is expected to decline further before leveling off in the intermediate term. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised of federal, state and local government operated services, is also projected to grow within the size of DEF's service area. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e. public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days and the sales month billing days, results in a significant level of explained variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-

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related energy use throughout the year . The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or sales for resale, customer of DEF that contracts for both seasonal and stratified loads over the forecast horizon. The municipal sales for resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Three customers in this class, Chattahoochee, Mt. Dora, and Williston, are municipalities whose full energy requirements are supplied by DEF. Energy projections for full requirement customers grow at a rate that approximates their historical trend with additional information coming from the respective city officials. DEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, and another power provider, RCID. In each case, these customers contract with DEF for a specific level and type of stratified capacity needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load and expected fuel prices.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF's coincident system peak is separated into five major components. These components consist of potential firm retail load, interruptible and curtailable tariff non-firm load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

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Potential firm retail load refers to projections of DEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's firm retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in load control reductions. Seasonal peaks are projected using the historical seasonal peak hour regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected. Energy conservation and direct load control estimates are consistent with DEF's DSM goals that have been established by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of firm retail monthly peak demand figures.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of monthly demands. The Full Requirement municipal demand forecast is estimated for individual cities using historically trended growth rates adjusted for current economic conditions.

DEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon as it has historically. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from DEF's large industrial accounts by account executives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand

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and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

CONSERVATION

On August 16, 2011, the PSC issued Order No. PSC-11-0347-PAA-EG, Modifying and Approving the Demand Side Management Plan of DEF (formerly known as Progress Energy Florida, Inc.). In this Order, the FPSC modified DEF's DSM Plan to consist of those existing programs in effect as of the date of the Order.

The following tables show the 2010 through 2014 achievements from DEF's existing set of DSM programs.

Residential Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	44	85	58
2011	83	160	111
2012	118	233	159
2013	144	281	200
2014	169	322	243

Commercial Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	36	31	66
2011	65	61	132
2012	94	82	199
2013	121	103	243
2014	157	133	300

Total Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	80	116	124
2011	148	221	243
2012	212	315	358
2013	265	384	442
2014	326	455	542

DEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs that will continue to be offered through 2015. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. A brief description of each of the currently offered DSM programs is provided below.

In 2012, DEF received administrative approval of revisions to four programs as a result of changes to the Florida Building Code: Home Energy Improvement, Residential New Construction, Business New Construction and Better Business. The Building Code changes resulted in increased minimum efficiency levels which resulted in an increase in the baseline efficiency level from which DEF provides incentives. The revisions to the four programs are incorporated in the descriptions below.

In 2013, the increased efficiency standards impacted participation in DEF's approved DSM programs as measures that previously were eligible for incentives became required standards ineligible for incentives. The higher performance requirements established by the changes to the Florida Building Code, along with the state and federal minimum efficiency standards for residential appliances and commercial equipment, resulted in a reduction of demand and energy savings from DEF's DSM programs. As the U.S. Department of Energy (DOE) continues the implementation of increased energy efficiency standards for residential and commercial end-uses, the amount of demand and energy savings captured by DEF's DSM programs will decrease. On March 16, 2015, DEF submitted new programs to the PSC designed to meet the

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goals established in Docket Number 130200-EI. If the new programs are approved by the Commission this year, DEF will reflect the changed programs, and resulting demand and energy savings, in its next TYSP filing.

DEF's CURRENTLY APPROVED DSM PROGRAMS:

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides residential customers with an analysis of their current energy use and provides recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program currently offers DEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-Completed Mail-In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit – a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III); and Type 7: Student Mail In Audit - a student-completed audit. The Home Energy Check program serves as the foundation of the Home Energy Improvement program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement

The Home Energy Improvement Program is the umbrella program that serves to increase energy efficiency for existing residential homes. All residential customers are eligible to participate in this program. The program includes a cost-effective and comprehensive portfolio of measures across all housing types designed to provide customer energy savings and reduce system demand.

The program provides incentives for a number of energy conservation measures including attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps.

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Residential New Construction

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the U.S. Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. Additional measures within the Residential New Construction program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler, and energy recovery ventilation.

Low Income Weatherization Assistance

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver

This program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead, refrigerator coil brush, HVAC filters, and weatherization measures (i.e. weather stripping, door sweeps, etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

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Residential Energy Management (EnergyWise)

This program allows DEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio-controlled switches installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated for usage in excess of 600 kWh per month.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of a free walk-through audit and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues as well as incentives on efficiency measures. The Better Business program promotes energy efficient HVAC, building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation, and Energy Star cool roof coating products), demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the State of Florida energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives are available for high efficiency HVAC equipment, energy recovery ventilation, Energy Star cool roof coating products, demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal energy storage and window film or screen.

Innovation Incentive

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for DEF customers. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak demand and/or energy, but are not addressed by other programs. Energy efficiency opportunities are identified by DEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to DEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces DEF's demand during peak or emergency conditions. As described in DEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent structures and utilized for the following purposes: 1) water heater(s), 2) central electric heating system(s), 3) central electric cooling system(s), and or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

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Standby Generation

This demand control program reduces DEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability of at least 50 kW, and are willing to reduce their demand when DEF deems it necessary. Customers participating in the Standby Generation program receive a monthly credit on their electric bills according to their demonstrated ability to reduce demand at DEF's request.

Interruptible Service

This direct load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. DEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for the ability to interrupt load, customers participating in the Interruptible Service program receive a monthly credit applied to their electric bills.

Curtailable Service

This load control program reduces DEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers who are willing to curtail demand. Customers participating in the Curtailable Service program receive a monthly credit applied to their electric bills.

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RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001(5)(f), Florida Administration Code). In accordance with the rule, the Technology Development program facilitates the research of innovative technologies and continued advances within the energy industry. DEF will undertake certain development, educational and demonstration projects that have potential to become DSM programs. Examples of projects included in this program include the evaluation of off-peak generation with energy storage for on-peak demand consumption, small-scale wind and smart charging for plug-in hybrid electric vehicles. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

DEMAND-SIDE RENEWABLE PORTFOLIO

Solar Water Heating for the Low-income Residential Customers Pilot

This pilot program is designed to assist low-income families with energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. DEF collaborates with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system is provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This pilot program encourages residential customers to install new solar thermal water heating systems on their residence with the requirement for customers to participate in our residential Energy Management program (EnergyWise). Participants receive a one-time $550 rebate designed to reduce the upfront cost of the renewable energy system, plus a monthly bill credit associated with their participation in the residential Energy Management program.

Residential Solar Photovoltaic Pilot

This pilot encourages residential customers to install new solar photovoltaic (PV) systems on their home. A DEF audit is required prior to system installation to qualify for this rebate. Participating customers will receive a one-time rebate of up to $20,000 to reduce the initial investment required to install a qualified renewable solar PV system. The rebate is based on the wattage of the PV (DC) power rating.

Commercial Solar Photovoltaic Pilot

This pilot encourages commercial customers to install new solar PV systems on their facilities. A DEF energy audit is required prior to system installation to qualify for this rebate. The program provides participating commercial customers with a tiered rebate to reduce the initial investment in a qualified solar PV system. The rebate is based on the PV (DC) power rating of the unit installed. The total incentives per participant will be limited to $130,000, based on a maximum installation of 100 kW.

Photovoltaic For Schools Pilot

This pilot is designed to assist schools with energy costs while promoting energy education. This program provides participating public schools with new solar photovoltaic systems at no cost to the school. The primary goals of the program are to:

- Eliminate the initial investment required to install a solar PV system
- Increase renewable energy generation on DEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in DEF communities and schools

The program will be limited to an annual target of one system with a rating up to 100 KW installed on a post secondary public school and ten 10 KW systems with battery backup option installed on public K-12 schools, preferably serving as emergency shelters.

150043 Hearing Exhibits 00053

Research and Demonstration Pilot

The purpose of this pilot program is to research technology and establish Research and Design initiatives to support the development of renewable energy pilot programs. Demonstration projects will provide real-world field testing to assist in the development of these initiatives. The program will be limited to a maximum annual expenditure equal to 5% of the total Demand-Side Renewable Portfolio annual expenditures.

150043 Hearing Exhibits 00054

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150043 Hearing Exhibits 00055

23. How has DEF accounted for the newly established DSM goals per Order No. PSC-14-0696-FOF-EU for the years 2015, 2016, and 2017 in its load forecast used to determine project cost effectiveness in the instant proceeding?

RESPONSE:

The projected DSM achievements were adjusted in the 2015 load forecast to align with the goals specified in the order. Please see the response to Question 15 for additional details.

150043 Hearing Exhibits 00056

24. Please describe the methodology and the assumptions that DEF used in arriving at its estimated future carbon prices.

RESPONSE:

At the time DEF developed its current CO_2 price forecast the future related to federal climate policy was highly uncertain. In June 2009 the House of Representatives passed H.R. 2454, the American Clean Energy and Security Act (commonly known as the Waxman-Markey bill). Passage of this measure represented the first time either chamber had passed a comprehensive bill to reduce greenhouse gas emissions. The bill would have established, among other things, an economy-wide greenhouse gas ("GHG") cap-and-trade program beginning in 2012. In the Senate, however, efforts to move that bill failed. After the failure of the Waxman-Markey bill and with the Republicans taking control in the House in the 2010 mid-term elections, serious talk of cap-and-trade legislation in Congress essentially ended. Today, DEF sees no indication that climate change legislation designed to establish a price on CO_2 emissions will be seriously debated through at least 2015.

In early 2013, some members of Congress proposed a carbon tax as a way to raise revenue for the federal government. No action was taken on those proposals. While some members of Congress might continue to advocate for a carbon tax, DEF considers it unlikely that a carbon tax will be adopted in the near term because we do not believe the Republican-controlled Congress would support such a measure. Therefore, DEF does not believe that Congress will consider legislation in the near term that establishes a price on CO_2 emissions.

While DEF does not believe Congress will enact climate change legislation in the near term, we recognize that it is possible, but not a certainty, that a future Congress could pass a bill resulting in a price being placed on CO_2 emissions.

In the alternative, USEPA continues to examine alternate regulations covering CO_2 emissions. While these may or may not take the form of an explicit tax or allowance fee, such regulations would clearly place an implied system cost for such emissions. DEF believes it is reasonable to consider such an outcome in our evaluations.

DEF's current assumption regarding the timing of possible federal climate change legislation for the purpose of reflecting that potential outcome in our analyses is that federal climate change legislation could be enacted in 2017 that would set a price on CO_2 emissions beginning in 2020. This timing was selected based on our belief that it will be several more years before the economy recovers to the point where Congress might be willing to seriously consider climate change legislation. DEF is not predicting what form any such legislation may take. In its Clean Power Plan proposal, EPA also selected 2020 as the starting year for CO_2 emission regulation.

Because of the uncertainty associated with potential future congressional action to pass legislation establishing a policy that would result in a price on CO_2 emissions, DEF also considers an alternative scenario where the price on CO_2 emissions is zero.

150043 Hearing Exhibits 00057

The EPA's recently proposed Clean Power Plan was not a consideration in the development of DEF's CO_2 price forecast. Because of the many uncertainties surrounding the promulgation and implementation of the CPP, DEF has not yet incorporated this into the formal forecasting process. Scenarios testing the impact of DEF's assumed carbon price against alternative interpretations of the CPP indicate that the carbon price produces changes in dispatch which are within the range of potential CPP requirements.

150043 Hearing Exhibits 00058

25. For the instant docket, has DEF re-evaluated the reasonableness of the carbon price forecast that the Company used in Docket No. 140110-EI? If "yes", please provide the re-evaluation results; if "no", please explain why not.

RESPONSE:

DEF has not substantially changed the carbon price forecast which is modeled as a national carbon tax on all fossil generation since the Fall 2013 Duke Energy Fundamental Outlook used in the analysis for Docket No 140111. The price on carbon is still assumed to begin in the year 2020 at $15/Metric Ton (2009$), then escalated at a 6% (real) inflation rate. However, beginning with the Spring 2014 Duke Energy Fundamental Outlook, the long term inflation rate was reduced slightly to 5% (real) inflation rate for all years beyond 2033. This carbon price forecast assumption remains in place today. Legislative discussions regarding a national tax on carbon have taken a back seat to the current focus on the EPA's rulemaking process regarding new source performance standards for greenhouse gases. While DEF is following the development process, there is still great uncertainty surrounding the issuance of a final set of new source performance standards for existing power generation. In June 2014, the EPA issued a set of proposed new source standards for existing generation under section 111(d) of the Clean Air Act, (this new rule is also widely referred to as the Clean Power Plan or "CPP"). Even if the final set of rules for existing generation closely follows the structure of the proposed standards, there is probably more uncertainty regarding the possible responses by the individual states, including Florida, to these new rules. The EPA structured this rule as an emissions rate standard to be applied to the entire electric power generation system, purportedly to allow the states flexibility in the design and implementation of their individual compliance plans. The EPA added yet more uncertainty by proposing that individual states consider joining with other neighboring states to form regional compacts. It is thus premature at this time to speculate on what (if any) carbon pricing mechanisms will eventually be adopted as part of any individual state compliance plan. Given the uncertain future of this rule in the judicial review process and the application of congressional oversight given the disparate impact on individual states, we could still see movement back toward a national price on carbon. DEF believes the price of carbon included in the current docket adequately represents an appropriate price on carbon for planning purposes.

150043 Hearing Exhibits 00059

26. Referring to Page 9, Line 22 through Page 10, Line 1 of Witness K. Delehanty's testimony, please answer the following questions:

a. Please explain in greater detail the Company's modeling attempt including the assumption, the methodology, and the results.

RESPONSE:

In the Fall of 2014, Duke Energy hired Energy Ventures Analysis (EVA) to produce a "sensitivity" to the Fall 2014 Duke Energy Fundamentals case. EVA was instructed to model the proposed clean power plan using the $C0_2$ emissions rate limits at the state level, as proposed by the EPA in their June 2014 proposed rule. Since the EPA mentioned, but did not issue any guidance on converting these state level rate limits to a set of equivalent mass caps, DEF assumed a strict interpretation of the rule as it was written. Essentially, DEF assumed that collectively, all the affected generation units in each state would be required to achieve a statewide rate limit as proposed by the EPA with no banking or allowance trading between states. Following the initial comment period, the EPA issued updated guidance in November 2014 on the conversion process to a set of equivalent mass based caps, but this was after DEF completed the rate limit study. The important difference between using the proposed rate limits (as DEF did), versus converting those rate limits to a set of equivalent mass caps, is in the treatment of early retirements of affected units. Modeled as a rate standard, coal retirements do not greatly impact the collective emissions rate of the remaining group of units affected by the rule. However, by virtue of converting the rate standard to a fixed mass cap, early coal retirements will often go a long way toward compliance with the cap, especially in coal heavy states.

To ensure that every state would achieve compliance with the proposed rate limits in the DEF study, EVA utilized an emissions optimization module in the Aurora model which utilizes carbon shadow prices to affect the dispatch price of generation based on the unit's carbon emissions rate. The model continues to internally raise the state level carbon shadow prices until every state comes into compliance. As expected, the resulting carbon shadow prices varied by state, but in general were above the single national carbon tax assumption used in this docket. However, these prices are not directly comparable since the carbon tax is applied to all generation while the carbon shadow prices are only applied to those existing units affected by the rule. Other major assumptions included in the DEF study:

- **Fewer age based nuclear retirements than the no carbon case**
- **A price elasticity function lowered demand levels below the no carbon case**
- **DEF did not include the 6% across the board improvement to coal heat rate efficiency as assumed by EPA**
- **DEF used its own estimates for energy efficiency and renewable energy penetration, rather than those assumed possible by the EPA**

The CPP rate limit case resulted in a higher demand for natural gas and higher gas prices than the no carbon case, conversely coal demand and prices moved lower.

150043 Hearing Exhibits 00060

b. Please provide the CO2 price forecast DEF used in the discussed modeling.

RESPONSE:

See confidential attachment "2014_10_07 - Duke 2014 Refresh - Carbon - Carbon Shadow Prices.xlsx" bearing Bates Nos. 15LGBRA-STAFFROG1-26b-000001 through 15LGBRA-STAFFROG1-26b-000003. These documents are subject to DEF's Third Notice of Intent to request confidential classification filed contemporaneously with service of this response.

c. Is the CO2 price forecast used in the modeling the same as the forecast used in evaluating the cost-effectiveness of the Osprey APA?

RESPONSE:

No. This sensitivity forecast was only used to inform DEF about how the proposed CPP might work in practice. The values used in evaluating the cost effectiveness of the Osprey acquisition were those derived earlier as described in the response to Questions 24 and 25 above.

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d. Is the CO2 price forecast used in the modeling the same as the forecast used in evaluating the cost-effectiveness of the base generation plan that includes the Suwannee Simple Cycle Project?

RESPONSE:

No. This sensitivity forecast was only used to inform DEF about how the proposed CPP might work in practice. The values used in evaluating the cost effectiveness of the Osprey acquisition were those derived earlier as described in the response to Questions 24 and 25 above.

150043 Hearing Exhibits 00061

27. Referring to Page 10 , Lines 14 – 19 of Witness K. Delehanty's testimony, please answer the following questions:

a. Why does DEF believe that the carbon price it used in the instant docket has been set at a level that is a reasonable trajectory to represent the risk of federal climate change legislation or regulation?

RESPONSE:

DEF believes that the carbon tax assumption represents a reasonable price trajectory for achieving the carbon emissions reduction goals outlined in the EPA's proposed CPP rule even if the approach is different. Absent a final section 111(d) rule, it is difficult to assign a price trajectory for any state, including Florida, since the EPA has purposely constructed this rule with state level flexibility (in compliance alternatives) in mind. Whenever EPA issues a final rule, the states will have up to three additional years to submit a State Implementation Plan to the EPA for approval. In the meantime there will be court challenges and there is always the possibility that Congress will choose to intervene by introducing legislation acceptable to the president. Given the level of uncertainty around this rule, DEF believes the national carbon tax assumption used in this docket represents a reasonable price trajectory for achieving the aspirational reductions sought by the EPA in a more uniform fashion.

b. Why does the Company believe that the carbon price it used in the instant docket is reflective of the pricing that policy makers may consider acceptable if or when they act?

RESPONSE:

DEF believes the carbon price trajectory included in this docket could allow for an orderly transition to lower carbon emitting sources within the power sector without causing massive economic displacement, assuming the tax revenues are used to reduce the economic impact to end use customers and industries.

150043 Hearing Exhibits 00062

28. Referring to Page 23, Line 25 through Page 26, Line 4 of Witness B. Borsch's testimony, please answer the following questions:

a. Is it correct that the higher the CO2 price, the more cost-effective the Osprey APA is when compared to the base generation plan including the Suwannee Simple Cycle Project?

RESPONSE:

Yes.

b. If your response to question 30a is "yes", please provide the break-even CO2 price.

RESPONSE:

DEF has not calculated a "break-even CO_2 price. As reflected in the responses to Questions 24 – 27, the CO_2 price is not a single value that can easily be adjusted to calculate a "break-even", but is a trajectory of prices dependent on the starting point and the escalation rate(s) over the period evaluated.

29. In terms of carbon emissions, would the Osprey APA or Suwannee Project more greatly reduce DEF's carbon emissions profile?

RESPONSE:

The Osprey acquisition provides the lower carbon footprint. The higher efficiency of the combined cycle displaces other less efficient units in the DEF generating stack in many hours, producing savings in both fuel and CO_2 emissions.

150043 Hearing Exhibits 00064

30. Please provide DEF's general assumptions (demographic and weather related) and economic assumptions used to prepare its 2015 TYSP and identify any significant change from those used in preparing the DEF 2014 TYSP.

RESPONSE:

Please refer to the assumptions in the DEF 2015 TYSP in Chapter Two (attached as an excerpt in response to Question 22) for information on economic, demographic, weather, large customers, etc. applied to the forecast. Besides the usual updated picture of the U.S. and Florida economies from Moody's Analytics and demographic update from the University of Florida's Bureau of Economic & Business research, both of which incorporate more recent actual trends in their updates, there were no significant changes between the two TYSPs.

150043 Hearing Exhibits 00065

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 24th day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 1-6, 8-15, 17-25, and 28-30 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24TH day of March, 2015.

Benjamin M.H. Borsch

Helen M. Kyriakou

Notary Public
State of Florida, at Large

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

My Commission Expires:
10-24-17

100615334.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 24th day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared EDWARD L. SCOTT, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 1 and 2 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of March, 2015.

Edward L. Scott

Notary Public
State of Florida, at Large

NICK BRANA
Notary Public - State of Florida
My Comm. Expires Sep 10, 2017
Commission # FF 052769

My Commission Expires:
SEPT. 10, 2017

100615348.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 20 day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared KRIS G. EDMONDSON, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory number 7 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20 day of March, 2015.

Kris G. Edmondson

Notary Public
State of Florida, at Large

My Commission Expires:
OCT 22, 2017

RENE' T. MEADE
Commission # FF 030607
Expires October 22, 2017

100615412.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 24 day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 8 and 9 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24 day of March, 2015.

Sarah Hirschman Ukes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF106231
Expires 3/23/2018

Thomas G. Foster

Sarah Hirschman Ukes

Notary Public
State of Florida, at Large

My Commission Expires:
3/23/2018

100615377.1

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 23rd day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MARK E. LANDSEIDEL, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory number 16 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of March, 2015.

M E Landseidel

Mark E. Landseidel

Shannon L. Wall

Notary Public

State of ~~Florida~~, at Large
North Carolina

My Commission Expires: 6-17-17

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 17, 2017

100615297.1

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this ___20th__ day of March, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared KEVIN E. DELEHANTY, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 24 through 27b STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this __20th_ day of March, 2015.

Kevin E. Delehanty

Kevin E. Delehanty

Nancy H. Taylor

Notary Public
State of North Carolina, at Large

My Commission Expires:
January 24, 2017

NANCY H. TAYLOR NOTARY PUBLIC MECKLENBURG COUNTY, NC

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20

DEF's Supplemental Responses to Staff's First Set of Interrogatories (Nos. 11b and 11c)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 20
PARTY: STAFF
DESCRIPTION: DEF's Supplemental Responses to Staff's First Set of Interrogatories (Nos. 11b and 11c) [Bates Nos.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI SERVED: APRIL 06, 2015

DUKE ENERGY FLORIDA, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES NOS. 11B. AND C.

Duke Energy Florida, Inc. ("DEF") provides its supplemental response to Staff's First Set of Interrogatories Nos. 11b. and c. as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's First Set of Interrogatories Nos. 1-30, filed on March 16, 2015, as if those objections were fully set forth herein.

INTERROGATORIES

11. Please complete Table 2 for the following scenarios using the same forecast data used in the instant filing (2014 Ten-Year Site Plan), as well as using the most recently available forecast data (six completed tables):

a) Neither Osprey nor Suwannee Projects are completed.
b) Osprey unit only integrated into system as planned.
c) Suwannee units only integrated into system as planned.

Table 2

	Annual Revenue Requirements for Fuel ($million)	Annual Revenue Requirements for Non-fuel O&M ($million)	Annual Impact on Residential Bill for 1,200 kWh/month ($)
2016			
2017			

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2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

SUPPLEMENTAL RESPONSE:

Osprey 2015 - 11.b

	Annual Revenue Requirements for Fuel ($million, Nominal)	Annual Revenue Requirements for Non-fuel O&M ($million, Nominal)	Impact on Residential Bill for 1,200 kWh/month ($)
2015	1,644	535	-
2016	1,668	570	-
2017	1,698	630	-
2018	1,851	740	-
2019	2,114	856	-
2020	2,378	1,296	-
2021	2,456	1,356	-
2022	2,536	1,415	-
2023	2,625	1,495	-
2024	2,731	1,490	-
2025	2,906	1,505	-
2026	3,022	1,538	-
2027	3,190	1,689	-
2028	3,319	1,820	-
2029	3,494	2,003	-
2030	3,637	2,143	-
2031	3,788	2,226	-
2032	3,960	2,296	-
2033	4,112	2,377	-
2034	4,267	2,582	-
2035	4,535	2,780	-
2036	4,792	2,872	-

2037	5,042	2,940	-
2038	5,300	3,060	-
2039	5,558	3,139	-
2040	5,872	3,205	-
2041	6,101	3,310	-
2042	6,341	3,440	-
2043	6,597	3,550	-

Notes:
* Residential bill impact displayed as a differential from Osprey 2015. 1,200 kWh/month rate based on average residential price.

Suwannee CTs 2015 - 11.c

	Annual Revenue Requirements for Fuel ($million, Nominal)	Annual Revenue Requirements for Non-fuel O&M ($million, Nominal)	Impact on Residential Bill for 1,200 kWh/month ($)
2015	1,644	535	(0.01)
2016	1,668	565	(0.16)
2017	1,706	581	(1.44)
2018	1,858	706	(0.97)
2019	2,115	828	(0.87)
2020	2,385	1,262	(0.76)
2021	2,458	1,327	(0.76)
2022	2,539	1,391	(0.56)
2023	2,637	1,480	0.02
2024	2,724	1,549	1.68
2025	2,874	1,606	2.21
2026	3,025	1,638	3.10
2027	3,177	1,791	2.69
2028	3,330	1,912	2.94
2029	3,488	2,093	2.43
2030	3,655	2,236	3.09
2031	3,804	2,305	2.56
2032	3,968	2,374	2.34
2033	4,122	2,448	2.13
2034	4,243	2,539	(1.68)
2035	4,532	2,644	(3.64)
2036	4,784	2,734	(3.72)
2037	5,049	2,842	(2.35)
2038	5,317	2,990	(1.41)
2039	5,575	3,069	(1.40)
2040	5,888	3,180	(0.23)
2041	6,118	3,279	(0.35)
2042	6,357	3,417	(0.17)
2043	6,614	3,535	0.01

Notes:

* Residential bill impact displayed as a differential from Osprey 2015. 1,200 kWh/month rate based on average residential price.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 6th day of April, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he provided the supplemental response to interrogatory numbers 11b and 11c from STAFF'S FIRST INTERROGATORIES NOS. 1 – 30 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150043-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of April, 2015.

Benjamin M.H. Borsch

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

/ Helen M Kyriakou
Notary Public
State of Florida, at Large

My Commission Expires:
10-24-2017

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21

DEF's Responses to Staff's Second Set of Interrogatories (Nos. 31-35)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 21
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Second Set of Interrogatories (Nos. 31-35) [Bates Nos. 00078-00092]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI SERVED: April 27, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES NOS. (31-35)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Second Set of Interrogatories (Nos. 31-35) as follows:

INTERROGATORIES

31. Refer to Witness Delehanty's Direct Testimony, Page 1, Lines 10-13. Please identify the forecast years included in Duke Energy Corporation's Fall 2013, Spring 2014, and Fall 2014 Long Term Fossil Fuel Price Forecasts.

RESPONSE:

The actual commodity price forecast periods delivered to Duke Energy by EVA for the cases listed are shown below.

1. **Fall 2013:**
    a. **Oil prices 2013 – 2035**
    b. **Gas and coal prices 2013 – 2037**
    c. **Power prices 2013 – 2040**
2. **Spring 2014:**
    a. **Oil prices 2014 – 2035**
    b. **Gas and coal prices 2014 – 2040**
    c. **Power prices 2014 – 2040**
3. **Fall 2014:**
    a. **Oil prices 2014 – 2035**
    b. **Gas and coal prices 2014 – 2040**
    c. **Power prices 2014 – 2040**

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32. Refer to Witness Delehanty's Direct Testimony, Page 11, Lines 2-5 and 14-17 for the following questions. Regarding Duke Energy's market fundamentals group, Duke Energy's fuel procurement group, and DEF:

a. Please explain the corporate structure and relationship between each entity.

RESPONSE:

In the context of this question, we are referring to the Resource Planning team supporting Florida, while the Market Fundamentals group and the Fuel Procurement group are corporate support functions supporting other jurisdictions as well as Florida.

Duke Energy's Market Fundamentals Group:
The market fundamentals group is a corporate support function housed within the finance group that reports up to Steve Young, CFO Duke Energy. Employees within the market fundamentals group are further classified as "shared services," which enables them to provide support to both regulated and commercial business units within Duke Energy. The primary role of this group is to facilitate the development of a long term fundamental commodities price outlook for planning purposes. The long term fundamental commodity prices are used as data inputs by the Fuel Procurement group who then develops the detailed plant specific delivered fuel cost estimates that go into the various planning models.

Duke Energy's Fuel Procurement Group:
The fuel procurement group is an operations and support function within the regulated generation fleet organization and reports up to Dhiaa Jamil EVP & President, Regulated Generation. The primary role of this organization is to procure fuel and transportation services for the entire regulated generation fleet, and to provide planning and logistics support to both the generating stations and the planning functions.

Duke Energy Florida (DEF):
In the context of this question, we are responding with regard to the DEF Integrated Resource Planning (IRP) team. The DEF IRP team provides regulatory support, evaluation, and guidance as well as being a customer of the fuel forecasts for use in integrated resource planning. The DEF Integrated Resource team reports to the Utility President, Alex Glenn and through him to Keith Trent, EVP Grid Solutions & President, Midwest & Florida.

b. What is the specific role, if any, DEF has in producing its delivered fuel price forecast?

RESPONSE:

The DEF IRP team advises and provides feedback to the market fundamentals group during the development of the delivered fuel price forecast. DEF IRP reviews preliminary versions of the forecast and works with the market fundamentals group in testing assumptions and reviewing draft output.

c. When does each group (i.e. market fundamentals group and fuel procurement group) forward its completed fuel forecast to the recipient group or entity within a typical year?

RESPONSE:

After receiving the long term fundamental forecast from the external consultant, the market fundamentals group performs certain validation checks and then sends the forecast to the fuel procurement group. These deliveries typically take place in February (Spring update) and October (Fall update).

The fuel procurement group prepares the calculations of the plant specific transportation costs model inputs for each regulated generating station in the Duke Energy fleet and delivers those data inputs to the modeling groups approximately 2 – 4 weeks after the long term fundamental forecast is received.

d. If there is any overlap in forecast years in the forecasts produced by these entities, thereby resulting in a change to DEF's ultimate commodity fuel price forecast, please identify the overlap and explain how the change was implemented.

RESPONSE:

For each scenario case, there is only one actual forecast utilized (i.e., the long term fundamental commodity price outlook). Duke Energy does incorporate forward market pricing (NYMEX futures etc.) to shape the near term portion of the forecast (first 3-5 years) to better align the near term portion of the forecast with current market conditions. The overlap period between the forward market price curve and the fundamental forecast (usually year 4 & 5) is called the transition period where prices are typically scaled between the two curves.

e. Which of these entity's fuel price forecasts includes basis?

RESPONSE:

The fundamental gas price outlook contains basis representing the price of gas delivered into specific market hubs (i.e. FGT Zone 1, FGT Zone 3 etc.) Fundamental oil prices also include some basis to specific market hubs (US Gulf Coast etc.)

33. Refer to Witness Delehanty's Direct Testimony, Exhibit No. KED-1, Page 9, Lines 3-8. Please identify and quantify all adjustments Duke Energy provided to EVA's Long Term Fuel Price Forecast under the following scenarios, and explain each such adjustment:

a. 2014 Spring Refresh Carbon Tax Scenario.

RESPONSE:

Duke Energy does not make adjustments to EVA's Fuel Price Forecast. As described in Witness Delehanty's May 27, 2014 Testimony, Exhibit No. KED-1, Duke Energy meets with EVA and reviews the input assumptions provided by EVA in a myriad of areas that affect the EVA's forecast and requests adjustments to these assumptions so that they more closely follow Duke Energy's assumptions relative to Duke Energy's service area. EVA's base forecast is national and not specific to Duke Energy or even Duke Energy's service area. In addition, many of the adjustments made cover the Duke Energy fleet as a whole and relate to the whole Duke Energy fleet rather than DEF specifically. Areas of adjustment from the EVA base Fuel Price Forecast to the Duke Energy specific forecast were in the areas listed here.

Outages:	**Align Forced Outage Rate to Duke Energy's assumed coal plant performance.**
Capital Costs:	**Use Duke Energy provided generic capital costs for all technologies.**
Retirements:	**Align unit retirement assumptions with Duke Energy projections.**
Environmental Projects:	**Align with Duke Energy plans and projected project costs.**
Load Outlook:	**EVA's Southeast Region sales growth rate was higher than Duke Energy's expectation by approximately 0.25%. Align. EVA's Southeast Region elasticity appeared high. Align with national average.**
Renewables:	**Use Duke Energy provided projections for renewable penetrations.**
Gas Basis:	**EVA provided values appear high. Use values provided from quotes received from transporters.**
Energy Efficiency:	**Align with Duke Energy assumptions for impacts of increasing Codes and Standards, Utility DSM programs, EV and PV growth.**
Carbon Tax:	**Use Duke Energy provided Carbon Tax projection.**
WACC:	**Use an average Duke Energy WACC.**

b. 2014 Fall Refresh Carbon Tax Scenario.

RESPONSE:

EVA issues its own long term fundamental forecast once a year in the Fall. Heading into the Fall of 2014, there were areas of focus that Duke Energy wanted to include in a Fall refresh. The first was an effort to model the EPA's just announced Clean Power Plan proposal for carbon, and the second was to include the latest supply and demand estimates included in EVA's new long term outlook. For the Fall 2014 refresh, Duke Energy asked EVA to use the same Duke specific assumptions offered in the Spring, except the base data set would now be the new Fall 2014 EVA case. Furthermore, Duke Energy requested that with respect to carbon, two alternative carbon scenarios should be run on this new data set. The first scenario case included a representation of the EPA's just proposed Clean Power Plan modeled as a set of strict rate limits for each state. The second carbon scenario included the same national carbon tax assumption which Duke Energy utilized in its Spring 2014 fundamental outlook. So even though both the Spring and Fall 2014 carbon tax cases incorporated essentially the same assumption changes requested by Duke Energy in part (a), the underlying EVA datasets to which they were applied, were quite different.

34. What are DEF's system average annual fuel commodity, transportation, and delivered cost ($/Mmbtu) for natural gas, oil, and coal for 2010-2014?

RESPONSE:

All figures in $/MMBtu

	2010		
Fuel Type	Commodity Cost	Transportation Cost	Delivered Cost
Heavy Oil	Note 1	Note 1	$10.74
Light Oil	Note 1	Note 1	$16.05
Coal	Note 1	Note 1	$4.03
Gas	$6.27	$0.72	$6.99

	2011		
Fuel Type	Commodity Cost	Transportation Cost	Delivered Cost
Heavy Oil	Note 1	Note 1	$10.97
Light Oil	Note 1	Note 1	$18.25
Coal	Note 1	Note 1	$3.82
Gas	$5.43	$0.89	$6.32

	2012		
Fuel Type	Commodity Cost	Transportation Cost	Delivered Cost
Heavy Oil	Note 1	Note 1	$12.12
Light Oil	Note 1	Note 1	$20.35
Coal	Note 1	Note 1	$3.83
Gas	$4.61	$0.93	$5.54

	2013		
Fuel Type	Commodity Cost	Transportation Cost	Delivered Cost
Heavy Oil	Note 1	Note 1	$12.93
Light Oil	Note 1	Note 1	$21.13
Coal	Note 1	Note 1	$3.94
Gas	$4.57	$1.06	$5.63

	2014		
Fuel Type	Commodity Cost	Transportation Cost	Delivered Cost
Heavy Oil	Note 1	Note 1	N/A
Light Oil	Note 1	Note 1	$21.97
Coal	Note 1	Note 1	$4.00
Gas	$4.59	$1.06	$5.65

Note 1: Heavy Oil, Light Oil and Coal are all fuel types held in inventory by DEF. The fuel expense reflected in DEF's fuel reporting reflects the weighted average cost of the inventory for the respective fuel type. Therefore, the commodity and transportation costs for these fuel types are combined in the total weighted average cost of inventory.

35. Refer to Witness Delehanty's direct testimony, Page 11, Lines 1-18. What are DEF's delivered natural gas, oil, and coal prices (nominal $/MMbtu) for 2015 through 2035 under the following scenarios:

RESPONSE:

Please note that in these responses below "Fuel Oil" refers to distillate oil. DEF projects no further consumption of residual fuel oil in its units.

a. 2013 Fall Refresh Carbon Tax Scenario

RESPONSE:

This is the base fuel forecast used for the 2014 TYSP generated in the fall of 2013. This was also used for the filings made in May 2014 and for the update to CPVRR for the Suwannee and Osprey Projects produced in the fall of 2014.

Year	Natural Gas	Fuel Oil	Coal Crystal River 1 & 2	Coal Crystal River 4 & 5
2014	4.28	$ 19.91	4.55	3.38
2015	4.42	$ 18.97	4.49	3.35
2016	4.54	$ 18.12	4.60	3.30
2017	5.23	$ 17.90	4.70	3.41
2018	5.73	$ 17.87	4.74	3.50
2019	6.01	$ 17.94	4.53	3.75
2020	6.59	$ 18.38	4.56	3.77
2021	6.90	$ 18.83	-	3.85
2022	7.13	$ 19.30	-	3.93
2023	7.35	$ 19.77	-	4.01
2024	7.61	$ 20.24	-	4.11
2025	7.88	$ 20.82	-	4.23
2026	8.19	$ 21.41	-	4.32
2027	8.48	$ 22.02	-	4.42
2028	8.75	$ 22.63	-	4.52
2029	9.03	$ 23.25	-	4.63
2030	9.34	$ 24.06	-	4.75
2031	9.66	$ 24.65	-	4.86
2032	10.03	$ 25.36	-	4.99
2033	10.40	$ 19.91	-	5.13

b. 2014 Spring Refresh Carbon Tax Scenario

RESPONSE:

This is the base fuel forecast generated in the spring of 2014. This forecast was not used in CPVRR calculations for the management reviews or filings.

Year	Natural Gas	Fuel Oil	Coal Crystal River 1 & 2	Coal Crystal River 4 & 5
2015	4.43	20.50	4.20	3.21
2016	4.36	19.75	4.33	3.23
2017	4.38	19.63	4.48	3.33
2018	5.29	19.33	4.62	3.43
2019	5.67	18.61	4.77	3.52
2020	6.21	18.06	4.84	3.51
2021	6.51	17.93	-	3.58
2022	6.81	17.99	-	3.67
2023	7.06	18.06	-	3.75
2024	7.45	18.30	-	3.84
2025	7.72	18.55	-	3.93
2026	8.00	18.85	-	4.02
2027	8.28	19.22	-	4.12
2028	8.51	19.61	-	4.22
2029	8.81	20.01	-	4.32
2030	9.04	20.42	-	4.43
2031	9.36	20.84	-	4.52
2032	9.68	21.28	-	4.63
2033	10.08	21.72	-	4.74

c. 2014 Fall Refresh Carbon Tax Scenario

RESPONSE:

This is the base fuel forecast generated in the fall of 2014 and used for the 2015 TYSP. This was also used to respond to Interrogatory #11 in Staff's First Set of Interrogatories to DEF.

Year	Natural Gas	Fuel Oil	Coal Crystal River 1 & 2	Coal Crystal River 4 & 5
2015	4.09	19.81	4.26	3.30
2016	4.11	19.71	4.29	3.39
2017	4.22	19.49	4.41	3.46
2018	4.62	19.48	4.53	3.63
2019	5.29	19.21	4.64	3.72
2020	6.33	18.59	4.72	3.69
2021	6.57	18.05	-	3.76
2022	6.83	17.75	-	3.83
2023	7.10	17.82	-	3.93
2024	7.37	18.06	-	4.02
2025	7.72	18.31	-	4.11
2026	8.01	18.61	-	4.21
2027	8.31	18.98	-	4.31
2028	8.61	19.37	-	4.40
2029	8.93	19.77	-	4.51
2030	9.25	20.18	-	4.61
2031	9.58	20.60	-	4.72
2032	9.93	21.04	-	4.84
2033	10.28	21.48	-	4.96

d. 2014 Fall Refresh CPP Scenario

RESPONSE:

This is the CPP Scenario generated in the fall of 2014. This forecast has not been used in the modeling.

Year	Natural Gas	Fuel Oil	Coal Crystal River 1 & 2	Coal Crystal River 4 & 5
2015	4.17	19.81	4.26	3.30
2016	4.29	19.71	4.29	3.39
2017	4.44	19.49	4.41	3.46
2018	4.76	19.48	4.53	3.63
2019	5.43	19.21	4.63	3.72
2020	6.72	18.59	4.44	3.54
2021	6.98	18.05	-	3.61
2022	7.24	17.75	-	3.67
2023	7.59	17.82	-	3.74
2024	7.88	18.06	-	3.82
2025	8.24	18.31	-	3.91
2026	8.55	18.61	-	4.01
2027	8.87	18.98	-	4.11
2028	9.21	19.37	-	4.22
2029	9.55	19.77	-	4.32
2030	9.91	20.18	-	4.43

e. 2015 Spring Refresh Carbon Tax Scenario

RESPONSE:

This case has not yet been prepared.

f. 2015 Spring Refresh CPP Scenario

RESPONSE:

This case has not yet been prepared.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 27th day of April, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he co-sponsored the response to interrogatory number 32 and provided the answers to interrogatory number(s) 34 AND 35 from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 31-35) in Docket No(s). 150043-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 27th day of April, 2015.

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

Benjamin M.H. Borsch

Helen M. Kyriakou
Notary Public
State of Florida, at Large

My Commission Expires:
10-24-17

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 23rd day of April, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared KEVIN E. DELEHANTY, who is personally known to me, and he acknowledged before me that he co-sponsored the response to interrogatory number 32 and provided the answers to interrogatory number(s) 31 AND 33 from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 31-35) in Docket No(s). 150043-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of April, 2015.

Kevin E. Delehanty

Kevin E. Delehanty

NANCY H. TAYLOR NOTARY PUBLIC MECKLENBURG COUNTY, NC

Nancy H. Taylor

Notary Public
State of North Carolina, at Large

My Commission Expires:
January 26, 2017

22

DEF's Responses to Staff's Third Set of Interrogatories (No. 42)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 22
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Third Set of Interrogatories (No. 42) [Bates Nos. 00093-00096]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI DATED: APRIL 30, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES NOS. (36-44)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Third of Interrogatories (Nos. 36-44) as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's Third Set of Interrogatories (Nos. 36-44), filed on April 27, 2015, as if those objections were fully set forth herein.

INTERROGATORIES

42. Please compare the cost to purchase the Osprey unit with the cost to build a similar new unit. If dollar amounts are not available, please identify relative differences in cost in percentages. Please consider only capital costs in this comparison.

RESPONSE:

Generation Capital Costs ($2017)

Generic Combined Cycle ($/kw)	1,103
Osprey ($/kw)	377

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 30th day of April, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 36 through 44 from STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 36-44) in Docket No(s). 150043-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of April, 2015.

Benjamin M.H. Borsch

Helen M. Kyriakou

Notary Public
State of Florida, at Large

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

My Commission Expires:
10-24-17

23

DEF's Supplemental Responses to Staff's Third Set of Interrogatories (Nos. 36-40)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 23
PARTY: STAFF
DESCRIPTION: DEF's Supplemental Responses to Staff's Third Set of Interrogatories (Nos. 36-40) [Bates Nos.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI DATED: May 18, 2015

DUKE ENERGY FLORIDA, INC.'S SUPPLEMENTAL RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES NOS. (36-44)

Duke Energy Florida, Inc. ("DEF") supplements its April 30, 2015 response to Staff's Third of Interrogatories (Nos. 36-44), specifically numbers 36, 37, 38, 39, and 40 as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's Third Set of Interrogatories (Nos. 36-44), filed on April 27, 2015, as if those objections were fully set forth herein.

INTERROGATORIES

36. Please describe how the High Case and Low Case Summer Peak Demand Forecasts, provided in response to Staff's Request for Production Number 22 were developed.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015.

DEF performs a statistical analysis of numerous input variables including population growth, economic forecasts, weather trends, trends in household formation, and specific trends in commercial, industrial and governmental sector behavior, including drivers related to the financial crisis and recovery. DEF incorporates projections of customer behavior and participation in energy efficiency activity, identified through appliance saturation studies, including utility sponsored activity, that driven by codes and standards, and as a result of price elasticity. Projections of customer participation in behind the meter generation (e.g., rooftop solar) and new device usage (e.g., electric vehicles) are also incorporated into the forecast.

DEF has not provided a High or Low Peak Demand Forecast based on the Company's high level of rigor in the production of the input estimates to the model

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used to produce the base forecast. The methodology for the development of the Base Peak Demand Forecast (summer and winter) is discussed in responses to Staff's First Set of Interrogatories Number 22 and in Chapter 2 of the Ten Year Site Plan (both 2014 and2015).

For the purpose of the response to these interrogatories (Numbers 36 – 38) and the associated Requests for Production of Documents (Numbers 22 – 24), DEF performed a statistical analysis of the variation in the projected energy for retail use, with a variation of one standard deviation from the mean (Base Forecast). The resulting values were adjusted for Company use and retail loss factors. The values were then applied to a Summer and Winter Load Factor using the Forecast Retail Requirements and the Total Retail Summer & Winter Peak MW Base forecasts to project High and Low Case Values for the Retail Peak Demand. Summer/Winter Contracted Wholesale Demand Requirements are then added to create Total System Summer/Winter Demand Cases. Finally, all DLC programs are summed for Summer and Winter impacts and are applied to Total to result in Firm Peak Demand for each of the requested cases.

It should be recognized that while this methodology gives an approximation of the statistical variation expected in the load over the forecast period, it is not a true representation of independent high and low case forecasts. To prepare those forecasts would require forecasts of the variation in each of the individual inputs to the model (customer growth, economic behavior, etc.) and the preparation of separate model cases for each forecast.

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37. Please describe how the High Case and Low Case Winter Peak Demand Forecasts provided in response to Staff's Request for Production Number 23 were developed.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. Please see the response to Question 36.

38. Please describe how the High Case and Low Case Forecasts of Summer and Winter Peak Demand provided in response to Staff's Request for Production Number 24 were developed.

a. What probabilities are assigned to the Company's Summer Peak Demand Base Case, High Case, and Low Case Forecasts for 2015 to 2024?

b. What probabilities are assigned to the Company's Winter Peak Demand High Case, Base Case, and Low Case Forecasts for 2015 to 2024?

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. Please see the response to Question 36.

DEF does not assign a numeric likelihood to the load forecast scenarios. As explained in the response to Question 36, DEF did not produce a fundamental high and low forecast. To do this, the Company would need to assign accurate probability estimates for each input variable including economic forecasts, forecasts of customer growth, customer behavior, energy efficiencies and so forth. In the statistical case prepared for these responses, each customer class' energy model's "Standard Error" is multiplied by the probability factor resulting in high/low bands at the one standard deviation confidence interval. The High and Low Load Cases represent statistical variations and not necessarily independent future outcomes using different sets of assumptions.

DEF's goal in producing and reviewing the Base Load Forecast is to ensure that the plans selected are robust under a variety of plausible future conditions. Notwithstanding the above, DEF believes that the most likely scenario of those presented is the reference case.

39. Please complete the table below for the following scenarios using total installed capacity per the Company's 2015 Ten-Year Site Plan and the Company's High Case Summer Peak Demand Forecast provided in response to Staff's Request for Production Number 24.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015.

a. Neither Osprey nor Suwannee Projects are completed

b. Osprey unit only integrated into system as planned.

c. Suwannee units only integrated into system as planned.

For each scenario, please identify and include the effects of any planned retirements of existing generation units, other unit additions (including Citrus County), as well as expiration of PPAs and any other changes to the DEF system that are currently anticipated.

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Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand – High Case (Summer)
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			

RESPONSE:

a. Neither Osprey nor Suwannee Projects are completed.

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - High Case (Summer)
2015	20%	11,213	9,323
2016	19%	11,205	9,396
2017	13%	10,904	9,678
2018	12%	11,013	9,837
2019	14%	11,733	10,252
2020	12%	11,624	10,390
2021	13%	11,624	10,314
2022	11%	11,624	10,465
2023	10%	11,624	10,601
2024	9%	11,726	10,713

b. **Osprey unit only integrated into system as planned.**

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - High Case (Summer)
2015	20%	11,213	9,323
2016	19%	11,205	9,396
2017	15%	11,148	9,678
2018	14%	11,257	9,837
2019	17%	11,977	10,252
2020	17%	12,199	10,390
2021	18%	12,199	10,314
2022	17%	12,199	10,465
2023	15%	12,199	10,601
2024	15%	12,301	10,713

c. **Suwannee units only integrated into system as planned.**

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - High Case (Summer)
2015	20%	11,213	9,323
2016	19%	11,205	9,396
2017	15%	11,149	9,678
2018	14%	11,229	9,837
2019	18%	12,049	10,252
2020	15%	11,940	10,390
2021	16%	11,940	10,314
2022	15%	11,990	10,465
2023	15%	12,143	10,601
2024	14%	12,236	10,713

The Osprey acquisition case has been used for calculation of reserve margin for both the response to Questions 39a and 39b. These cases are described in the 2015 Ten-Year Site Plan filed on April 1, 2015.

This case includes the retirements of the Turner Units in 2015 and 2016, the Avon Park Units in 2016 and Rio Pinar in 2016. The Osprey PPA starts in October 2014 and continues through December 2016. The Hines Units have summer capacity uprates through the installation of Inlet Chilling in 2016. Suwannee Steam Units 1 and 2 retire in 2017, while Suwannee Unit 3 continues operation until the completion of local area transmission projects in 2017 and retires in that spring. As described, this plan also includes the derate in 2016 of Crystal River units 1 and 2 and their retirement in 2018 at the in service date of the first Citrus CC power block. The second Citrus CC Power Block enters service later in that year. The Higgins Units retire in 2020. The full capacity of the Osprey acquisition is available in year 2020 once the transmission upgrades are completed. An undesignated PPA extends from Spring 2021 to Spring 2025. The current PPA from Shady Hills expires in 2024 and in that year, DEF proposes the construction of 4 simple cycle CT units at an undesignated site.

The response to Question 39c is based on the Suwannee CT case. This case differs from the Osprey case in that Suwannee Unit 3 retires in 2017 at the in-service of the new Suwannee Peakers. In addition, because the Suwannee Peakers have a smaller capacity than the full Osprey facility, an additional simple cycle CT is needed in 2023 and a Combined Cycle is proposed in 2024.

40. Please complete the table below for the following scenarios using total installed capacity per the Company's 2015 Ten-Year Site Plan and the Company's Low Case Summer Peak Demand Forecast provided in response to Staff's Request for Production Number 24.

a. Neither Osprey nor Suwannee Projects are completed.

b. Osprey unit only integrated into system as planned.

c. Suwannee units only integrated into system as planned.

For each scenario, please identify and include the effects of any planned retirements of existing generation units, other unit additions (including Citrus County), as well as expiration of PPAs and any other changes to the DEF system that are currently anticipated.

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - Low Case (Summer)
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. Please see the response to Question 39 regarding the plans.

a. Neither Osprey nor Suwannee Projects are completed.

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - Low Case (Summer)
2015	30%	11,213	8,650
2016	30%	11,205	8,634
2017	22%	10,904	8,918
2018	22%	11,013	9,063
2019	24%	11,733	9,462
2020	21%	11,624	9,586
2021	22%	11,624	9,495
2022	21%	11,624	9,633
2023	19%	11,624	9,757
2024	19%	11,726	9,862

b. Osprey unit only integrated into system as planned.

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - Low Case (Summer)
2015	30%	11,213	8,650
2016	30%	11,205	8,634
2017	25%	11,148	8,918
2018	24%	11,257	9,063
2019	27%	11,977	9,462
2020	27%	12,199	9,586
2021	28%	12,199	9,495
2022	27%	12,199	9,633
2023	25%	12,199	9,757
2024	25%	12,301	9,862

c. Suwannee units only integrated into system as planned.

Year	Reserve Margin (%)	Total Installed Capacity in DEF's 2015 TYSP	Peak Demand - Low Case (Summer)
2015	30%	11,213	8,650
2016	30%	11,205	8,634
2017	25%	11,149	8,918
2018	24%	11,229	9,063
2019	27%	12,049	9,462
2020	25%	11,940	9,586
2021	26%	11,940	9,495
2022	24%	11,990	9,633
2023	24%	12,143	9,757
2024	24%	12,236	9,862

Please see the response to Question 39 for the effects of any planned retirements of existing generation units, other unit additions (including Citrus County), as well as expiration of PPAs and any other changes to the DEF system that are currently anticipated.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 20th day of May, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he provided the supplemental responses to interrogatory number(s) 36 through 40 from STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 36-44) in Docket No(s). 150043-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of May, 2015.

Benjamin M.H. Borsch

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

Notary Public
State of Florida, at Large

My Commission Expires:
10-24-2017

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination that the Osprey Plant Acquisition and, alternatively, the Suwannee Simple Cycle Project is the most Cost Effective Generation Alternative to meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.	)	DOCKET NO. 150043-EI Submitted for filing: April 27, 2015

DUKE ENERGY FLORIDA, INC.'S OBJECTIONS TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 36-44)

Pursuant to Florida Administrative Code Rule 28-106.206, Rules 1.340 and 1.280 of the Florida Rules of Civil Procedure, and the Order Establishing Procedure, Order No. PSC-15-0110-PCO-EI, issued Feb. 20, 2015 (the "Order") in this matter, Duke Energy Florida, Inc. ("DEF") serves its objections to the Staff of the Florida Public Service Commission ("Staff") Third Set of Interrogatories (Nos. 36-44) and states as follows:

GENERAL OBJECTIONS

DEF objects to the interrogatories to the extent that they call for documents protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law. DEF will provide a privilege log within a reasonable time or as may be agreed to by the parties if an interrogatory calls for the production of privileged or protected documents or information. Moreover, DEF will include in its privilege log only the information required by Florida law and not some inconsistent and additional requirement under the Instructions and Definitions.

Further, in certain circumstances, DEF may determine upon investigation and analysis that documents responsive to certain interrogatories to which objections are not otherwise asserted are confidential and proprietary and should be produced only under an appropriate confidentiality agreement and protective order, if at all. By agreeing to provide such information

150043 Hearing Exhibits 00110

in response to such a request, DEF is not waiving its right to insist upon appropriate protection of confidentiality by means of a confidentiality agreement, protective order, or the procedures otherwise provided by law. DEF hereby asserts its right to require such protection of any and all information that may qualify for protection under the Florida Rules of Civil Procedure, and all other applicable statutes, rules, and legal principles.

By agreeing to provide information in response to an interrogatory, DEF is not waiving its right to object to the introduction of such information into evidence at the hearing of this matter.

DEF further objects to the Definitions to the extent that they seek to impose requirements on the responses to the Interrogatories beyond the requirements of the Florida Rules of Civil Procedure. DEF will respond to all interrogatories consistent with the requirements of the Florida Rules of Civil Procedure, and not some inconsistent and additional requirement under the Definitions.

SPECIFIC OBJECTIONS

With respect to Interrogatory Nos. 36, 37, 38, 39 and 40 DEF objects to these interrogatories because they request information that DEF does not have and that does not exist because DEF has no existing methodology and therefore no analyses prepared to generate the requested information.

Respectfully submitted this 27th day of April, 2015.

/s/ Blaise N. Gamba

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24

DEF's Responses to Staff's Fourth Set of Interrogatories (Nos. 45-46)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 24
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Fourth Set of Interrogatories (Nos. 45-46) [Bates Nos. 00112-00116]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI DATED: May 18, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FOURTH SET OF INTERROGATORIES NOS. (45-46)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fourth Set of Interrogatories (Nos. 45-46) as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's Fourth Set of Interrogatories (Nos. 45-46), filed on May 11, 2015, as if those objections were fully set forth herein.

INTERROGATORIES

45. Please refer to Witness Borsch's direct testimony, Exhibit ___(BMHB-3).

a. Consistent with the scenarios presented in this exhibit, please provide the "Cumulative PV Revenue Requirements Comparison – Acquisition Options vs Self Build" scenario based on "Osprey vs Self Build – Low Fuel – With CO2". In constructing this scenario, please use the 2013 Duke Fall Refresh Low Gas Price Sensitivity as provided in response to Staff's 2nd Request for Production of Documents, No. 14.

RESPONSE:

Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self Build				
$M 2015	Osprey vs Self Build - Mid Fuel - No CO2	Osprey vs Self Build - Low Fuel - With CO2	Osprey vs Self Build - Mid Fuel - With CO2	Osprey vs Self Build - High Fuel - With CO2
Capital Costs	(11)	(11)	(11)	(11)
Fuel	66	34	46	77
Emissions	(0)	124	132	124
Variable Costs	72	67	63	61
Fixed Costs	(136)	(136)	(136)	(136)
PPAs	(19)	(15)	(24)	(25)
Cogens	5	(5)	(9)	(8)
Emergency Energy	(1)	(1)	(1)	(1)
Positive - Osprey Acquisition Savings	(24)	58	61	81

b. Please weigh the relative likelihood of each scenario described in Witness Borsch's direct testimony, Exhibit ___(BMHB-3) and DEF's response to 45.a. above, based on the various 2013 and 2014 alternative fuel forecasts (nominal $/Mmbtu) provided in response to Staff's 2nd Request for Production of Documents, No. 14, and the most recent fuel price forecast information available to the company.

RESPONSE:

DEF does not assign a numeric likelihood to the fundamental fuel price scenarios. To do this, the Company would need to assign accurate probability estimates for each input variable when many are subjective matters of future environmental and regulatory policies. The fundamentals are built upon "expected" values operating under normal conditions, given the information we possess today. Short term imbalances can lead to wide short term price swings above or below the fundamental trend lines, but they are not considered to be sustainable price levels under the assumed conditions. The scenarios and sensitivity cases represent plausible future outcomes using different sets of assumptions and while they may be considered less "likely" outcomes than the reference case, they are certainly not meant to be bounding cases either. Notwithstanding the above, DEF believes that the most likely scenario of those presented is the reference case (mid fuel with CO2).

DEF's goal in producing and reviewing the fundamental fuel price scenarios is to ensure that the plans selected are robust under a variety of plausible future conditions for fuel price.

46. Please refer to DEF's responses to Staff's 2nd Request for Production of Documents, No. 20.c and Staff's 2nd Set of Interrogatories, No. 32.c. If the 2015 Spring Refresh Carbon Tax Scenario Natural Gas Price Forecast is not yet finalized, please identify the date when it will be finalized and the pending steps for finalization.

RESPONSE:

The referenced forecast was approved on May 11, 2015. Please refer to the response to Staff's Fourth Request for Production of Documents (No. 25).

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 20th day of May, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN M.H. BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 45 and 46 from STAFF'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 45-46) in Docket No(s). 150043-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of May, 2015.

Benjamin M.H. Borsch

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

Notary Public
State of Florida, at Large

My Commission Expires:
10-24-2017

25

DEF's Responses to Staff's First Request for Production of Documents (Nos. 12 and 13)

See Staff Exhibit CD for the responsive Excel files

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 25
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's First Request for Production of Documents (Nos. 12 and 13)See Staff Exhib...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI SERVED: March 25, 2015

REDACTED

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO
STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-13)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Request for Production of Documents (Nos. 1-13) as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's First Request for Production of Documents Nos. 1-13, filed on March 16, 2015, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

12. Please refer to Witness Borsch's direct testimony, Page 31. Please provide DEF's load, economic, and financial forecasts used to prepare the 2015 TYSP to the extent they are currently available, in hard copy and electronic format (in Excel, with formulas unlocked).

RESPONSE:

Please see Excel files bearing Bates Numbers 15LGBRA-STAFFPOD1-12-000001 through 15LGBRA-STAFFPOD1-12-000020.

13. Please provide DEF's general assumptions (demographic and weather related) and economic assumptions used to prepare its 2015 TYSP and identify any significant change from those used in preparing the DEF 2014 TYSP.

RESPONSE:

Please see Excel file detailing the DEF 2015 TYSP customer forecast bearing Bates Numbers 15LGBRA-STAFFPOD1-13-000001 through 15LGBRA-STAFFPOD1-13-000004. Please also see the documents produced in response to Question #12 above.

Respectfully submitted this 25th day of March, 2015.

Blaise N. Gamba

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6/4/2015

26

DEF's Responses to Staff's Second Request for Production of Documents (Nos. 14 (CONFIDENTIAL), and 19-20)

See Staff Exhibit CD for the responsive Excel files

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 26
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Second Request for Production of Documents (Nos. 14 (CONFIDENTIAL) and 19...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI SERVED: April 27, 2015

DUKE ENERGY FLORIDA, INC.'s RESPONSE TO STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 14-20)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Second Request for Production of Documents (Nos. 14-20) as follows:

14. Please provide each of Duke's natural gas commodity price forecasts referenced in Witness Delehanty's Direct Testimony, Exhibit No. KED-2, in hard copy and Excel format.

RESPONSE:

See Confidential Workbook Titled: *"2014 Gas Price Updates to the Fall 2013 Forecast.xlsx"* bearing Bates 15LGBRA-STAFFPOD2-14-000001 through 15LGBRA-STAFFPOD2-14-000006. This workbook is subject to DEF's Fifth Notice of Intent to Request Confidential Classification filed and served contemporaneously with this response.

19. Please provide Duke Energy's natural gas commodity fuel price forecast model, including forecast equations, assumptions, input data, data sources, results, statistical output, and summary reviews, in electronic format with formulas intact, under the following scenarios:

a. 2013 Fall Refresh Carbon Tax Scenario

b. 2014 Fall Refresh Carbon Tax Scenario

c. 2014 Fall Refresh CPP Scenario

RESPONSE:

Duke Energy does not have a gas forecast model. Duke Energy hires nationally known energy consultants with forecasting expertise to run their fundamental forecasting models using a mutually agreed upon set of assumptions. These three forecast scenarios were all run by Energy Ventures Analysis (EVA).

20. Refer to Witness Delehanty's direct testimony, Page 11, Lines 1-18. Please provide DEF's fuels procurement group's commodity, fuel transportation, and delivered natural gas fuel price forecasts, specific to the Osprey Plant and the alternative Suwanee Simple Cycle Plant, in hard copy and Excel format under the:

a. 2013 Fall Refresh Carbon Tax Scenario

RESPONSE:

See attached file *2013 Fall Refresh Carbon Tax Scenario Natural Gas.xlsx* bearing Bates Nos. 15-LGBRA-STAFFPOD2-20a-000001 through 15-LGBRA-STAFFPOD2-20a-000002.

b. 2014 Fall Refresh Carbon Tax Scenario

See attached file *2014 Fall Refresh Carbon Tax Scenario Natural Gas.xlsx* bearing Bates Nos. 15-LGBRA-STAFFPOD2-20b-000001 through 15-LGBRA-STAFFPOD2-20b-000002.

c. 2015 Spring Refresh Carbon Tax Scenario

RESPONSE:

This case has not yet been finalized.

/s/ Blaise N. Gamba

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic and U.S. mail this 27th day of April, 2015.

/s/ Blaise N. Gamba
Attorney

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6/4/2015

27

DEF's Supplemental Responses to Staff's Third Request for Production of Documents (Nos. 22-24)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 27
PARTY: STAFF
DESCRIPTION: DEF's Supplemental Responses to Staff's Third Request for Production of Documents (Nos. 22-24) [Bate...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI DATED: May 18, 2015

DUKE ENERGY FLORIDA, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD REQUEST FOR PRODUCTION (NOS. 21-24)

Duke Energy Florida, Inc. ("DEF") supplements its response to Staff's Third Request for Production of Documents (Nos. 21-24), specifically numbers 22, 23, and 24 as follows:

OBJECTIONS

DEF incorporates and restates its Objections to Staff's Third Request for Production (Nos. 21-24), filed on April 27, 2015, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

22. Referring to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-1, Page 80 of 224 (2014 Ten Year Site Plan) presenting DEF's history and forecast of summer peak demand – base case," please provide the Company's High Case and Low Case Summer Peak Demand Forecasts.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. See also DEF's response to Staff Interrogatory #36.

SYSTEM FIRM SUMMER MW			
Year	Base	High	Low
2014	8,812	9,198	8,534
2015	9,042	9,454	8,687
2016	9,149	9,585	8,833
2017	9,307	9,750	8,983
2018	9,439	9,878	9,116
2019	9,813	10,249	9,456
2020	9,935	10,406	9,579
2021	9,952	10,422	9,595
2022	10,067	10,531	9,693
2023	10,172	10,609	9,765

23. Referring to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-1, Page 81 of 224 (2014 Ten Year Site Plan) regarding DEF's history and forecast of winter peak demand – base case, please provide the Company's High Case and Low Case Winter Peak Demand Forecasts.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. See also DEF's response to Staff Interrogatory #36.

SYSTEM FIRM WINTER MW			
Year	Base	High	Low
2014	9,133	9,501	8,826
2015	9,370	9,759	8,990
2016	9,298	9,715	8,953
2017	9,544	9,972	9,188
2018	9,639	10,074	9,278
2019	9,971	10,389	9,584
2020	10,059	10,506	9,679
2021	10,144	10,593	9,758
2022	10,224	10,668	9,825
2023	10,298	10,711	9,865

24. Please refer to DEF's responses to Staff's First Set of Interrogatories, Nos. 21 & 22, which reference DEF's forecasted summer and winter net firm demands (peak demands) as contained in its 2015 Ten Year Site Plan.

a. Please provide the Company's Base Case, High Case, and Low Case Forecasts of Summer Peak Demand for 2015 to 2024.

b. Please provide the Company's Base Case, High Case, and Low Case Forecasts of Winter Peak Demand for 2015 to 2024.

RESPONSE:

Please see DEF's Objections filed on April 27, 2015. See also DEF's response to Staff Interrogatory #36.

a.

SYSTEM FIRM SUMMER MW			
Year	Base	High	Low
2015	8,932	9,323	8,650
2016	8,986	9,396	8,634
2017	9,237	9,678	8,918
2018	9,390	9,837	9,063
2019	9,797	10,252	9,462
2020	9,948	10,390	9,586
2021	9,847	10,314	9,495
2022	9,993	10,465	9,633
2023	10,133	10,601	9,757
2024	10,273	10,713	9,862

b.

SYSTEM FIRM WINTER MW			
Year	Base	High	Low
2015	9,487	9,870	9,168
2016	9,610	10,009	9,220
2017	9,558	9,987	9,204
2018	9,666	10,099	9,306
2019	9,779	10,220	9,413
2020	10,138	10,563	9,745
2021	10,093	10,541	9,712
2022	10,196	10,648	9,809
2023	10,298	10,744	9,895
2024	10,396	10,813	9,959

Respectfully submitted,

/s/ Blaise N. Gamba

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic mail this 18th day of May, 2015.

/s/ Blaise N. Gamba
Attorney

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DEF's Responses to Staff's Fourth Request for Production of Documents (No. 25)

See Staff Exhibit CD for the responsive Excel files

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 28
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Fourth Request for Production of Documents (No. 25) See Staff Exhibit CD ...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination that the Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet remaining need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 150043-EI DATED: May 18, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION (No. 25)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fourth Request for Production of Documents (No. 25) as follows:

DOCUMENT REQUESTS

25. Please refer to DEF's response to Staff's 2nd Request for Production of Documents, No. 20.c. Please provide the 2015 Spring Refresh Carbon Tax Scenario Natural Gas Price Forecast to the extent it is now finalized.

RESPONSE:

Please see attached document bearing Bates number 15LGBRA-STAFFPOD4-25-000001.

Respectfully submitted,

/s/ Blaise N. Gamba

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic mail this 18th day of May, 2015.

/s/ Blaise N. Gamba
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DEF NATURAL GAS DISPATCH PRICES

Month	Year	Base HH Regular Supply Cost	Physical Basis FGT Z3	Base Cost Regular Supply Z3	Average MMBTU Variable Cost	Average Variable MMBTU Delivered Costs
Feb	2015	2.866	$ 0.015	$ 2.881	$0.08	2.97
Mar	2015	2.842	$ 0.029	$ 2.872	$0.08	2.96
Apr	2015	2.830	$ 0.075	$ 2.905	$0.09	2.99
May	2015	2.697	$ 0.075	$ 2.772	$0.08	2.85
Jun	2015	2.980	$ 0.075	$ 3.055	$0.09	3.14
Jul	2015	3.077	$ 0.075	$ 3.152	$0.09	3.24
Aug	2015	3.100	$ 0.075	$ 3.175	$0.09	3.27
Sep	2015	3.069	$ 0.075	$ 3.144	$0.09	3.23
Oct	2015	3.087	$ 0.075	$ 3.162	$0.09	3.25
Nov	2015	3.171	$ 0.038	$ 3.209	$0.09	3.30
Dec	2015	3.343	$ 0.027	$ 3.370	$0.10	3.47
Jan	2016	3.451	$ 0.030	$ 3.481	$0.10	3.58
Feb	2016	3.433	$ 0.030	$ 3.463	$0.10	3.56
Mar	2016	3.375	$ 0.030	$ 3.405	$0.10	3.50
Apr	2016	3.269	$ 0.120	$ 3.389	$0.10	3.49
May	2016	3.279	$ 0.120	$ 3.399	$0.10	3.50
Jun	2016	3.321	$ 0.120	$ 3.441	$0.10	3.54
Jul	2016	3.390	$ 0.120	$ 3.510	$0.10	3.61
Aug	2016	3.408	$ 0.120	$ 3.528	$0.10	3.63
Sep	2016	3.364	$ 0.120	$ 3.484	$0.10	3.58
Oct	2016	3.393	$ 0.121	$ 3.514	$0.10	3.61
Nov	2016	3.425	$ 0.040	$ 3.465	$0.10	3.56
Dec	2016	3.607	$ 0.028	$ 3.635	$0.10	3.74
Jan	2017	3.748	$ 0.032	$ 3.780	$0.11	3.89
Feb	2017	3.730	$ 0.031	$ 3.761	$0.11	3.87
Mar	2017	3.666	$ 0.032	$ 3.698	$0.10	3.80
Apr	2017	3.486	$ 0.121	$ 3.607	$0.10	3.71
May	2017	3.494	$ 0.121	$ 3.615	$0.10	3.72
Jun	2017	3.544	$ 0.121	$ 3.665	$0.10	3.77
Jul	2017	3.620	$ 0.121	$ 3.741	$0.11	3.85
Aug	2017	3.641	$ 0.121	$ 3.762	$0.11	3.87
Sep	2017	3.589	$ 0.121	$ 3.710	$0.10	3.81
Oct	2017	3.610	$ 0.122	$ 3.732	$0.11	3.84
Nov	2017	3.601	$ 0.038	$ 3.639	$0.10	3.74
Dec	2017	3.779	$ 0.026	$ 3.805	$0.11	3.91
Jan	2018	3.949	$ 0.030	$ 3.979	$0.11	4.09
Feb	2018	3.960	$ 0.030	$ 3.989	$0.11	4.10
Mar	2018	3.924	$ 0.030	$ 3.954	$0.11	4.06
Apr	2018	3.740	$ 0.115	$ 3.855	$0.11	3.96
May	2018	3.785	$ 0.115	$ 3.900	$0.11	4.01
Jun	2018	3.887	$ 0.115	$ 4.002	$0.11	4.11
Jul	2018	4.015	$ 0.115	$ 4.130	$0.11	4.24

Aug	2018	4.111	$	0.115	$	4.225	$0.12	4.34
Sep	2018	4.109	$	0.115	$	4.224	$0.12	4.34
Oct	2018	4.170	$	0.115	$	4.285	$0.12	4.40
Nov	2018	4.335	$	0.036	$	4.372	$0.12	4.49
Dec	2018	4.625	$	0.025	$	4.650	$0.13	4.78
Jan	2019	4.580	$	0.028	$	4.608	$0.13	4.73
Feb	2019	4.650	$	0.028	$	4.678	$0.13	4.81
Mar	2019	4.633	$	0.028	$	4.661	$0.13	4.79
Apr	2019	4.554	$	0.109	$	4.663	$0.13	4.79
May	2019	4.611	$	0.109	$	4.720	$0.13	4.85
Jun	2019	4.770	$	0.109	$	4.879	$0.13	5.01
Jul	2019	4.943	$	0.109	$	5.052	$0.14	5.19
Aug	2019	5.111	$	0.109	$	5.220	$0.14	5.36
Sep	2019	5.114	$	0.109	$	5.223	$0.14	5.36
Oct	2019	5.181	$	0.110	$	5.291	$0.14	5.43
Nov	2019	5.538	$	0.035	$	5.573	$0.15	5.72
Dec	2019	5.928	$	0.023	$	5.951	$0.16	6.11
Jan	2020	5.759	$	0.027	$	5.786	$0.16	5.94
Feb	2020	5.831	$	0.027	$	5.858	$0.16	6.01
Mar	2020	5.759	$	0.027	$	5.786	$0.16	5.94
Apr	2020	5.687	$	0.104	$	5.791	$0.16	5.95
May	2020	5.687	$	0.103	$	5.790	$0.16	5.95
Jun	2020	5.831	$	0.103	$	5.934	$0.16	6.09
Jul	2020	5.975	$	0.104	$	6.079	$0.16	6.24
Aug	2020	6.119	$	0.104	$	6.223	$0.17	6.39
Sep	2020	6.047	$	0.104	$	6.151	$0.16	6.32
Oct	2020	6.047	$	0.104	$	6.151	$0.16	6.32
Nov	2020	6.407	$	0.034	$	6.441	$0.17	6.61
Dec	2020	6.767	$	0.022	$	6.789	$0.18	6.97
Jan	2021	5.927	$	0.027	$	5.954	$0.16	6.11
Feb	2021	6.001	$	0.027	$	6.028	$0.16	6.19
Mar	2021	5.927	$	0.027	$	5.954	$0.16	6.11
Apr	2021	5.853	$	0.104	$	5.957	$0.16	6.12
May	2021	5.853	$	0.103	$	5.957	$0.16	6.12
Jun	2021	6.001	$	0.103	$	6.105	$0.16	6.27
Jul	2021	6.150	$	0.104	$	6.253	$0.17	6.42
Aug	2021	6.298	$	0.104	$	6.401	$0.17	6.57
Sep	2021	6.224	$	0.104	$	6.327	$0.17	6.50
Oct	2021	6.224	$	0.104	$	6.328	$0.17	6.50
Nov	2021	6.594	$	0.034	$	6.628	$0.18	6.80
Dec	2021	6.965	$	0.022	$	6.986	$0.18	7.17
Jan	2022	6.105	$	0.027	$	6.132	$0.16	6.30
Feb	2022	6.181	$	0.027	$	6.208	$0.17	6.37
Mar	2022	6.105	$	0.027	$	6.132	$0.16	6.30
Apr	2022	6.029	$	0.104	$	6.132	$0.16	6.30
May	2022	6.029	$	0.103	$	6.132	$0.16	6.30
Jun	2022	6.181	$	0.103	$	6.285	$0.17	6.45

Jul	2022	6.334	$	0.104	$	6.437	$0.17	6.61
Aug	2022	6.487	$	0.104	$	6.590	$0.17	6.76
Sep	2022	6.410	$	0.104	$	6.514	$0.17	6.69
Oct	2022	6.410	$	0.104	$	6.514	$0.17	6.69
Nov	2022	6.792	$	0.034	$	6.825	$0.18	7.01
Dec	2022	7.173	$	0.022	$	7.195	$0.19	7.38
Jan	2023	6.291	$	0.027	$	6.318	$0.17	6.49
Feb	2023	6.370	$	0.027	$	6.397	$0.17	6.57
Mar	2023	6.291	$	0.027	$	6.318	$0.17	6.49
Apr	2023	6.213	$	0.104	$	6.317	$0.17	6.49
May	2023	6.213	$	0.103	$	6.316	$0.17	6.48
Jun	2023	6.370	$	0.103	$	6.473	$0.17	6.64
Jul	2023	6.527	$	0.104	$	6.631	$0.18	6.81
Aug	2023	6.685	$	0.104	$	6.788	$0.18	6.97
Sep	2023	6.606	$	0.104	$	6.710	$0.18	6.89
Oct	2023	6.606	$	0.104	$	6.710	$0.18	6.89
Nov	2023	6.999	$	0.034	$	7.033	$0.19	7.22
Dec	2023	7.392	$	0.022	$	7.414	$0.19	7.61
Jan	2024	6.483	$	0.027	$	6.510	$0.17	6.68
Feb	2024	6.564	$	0.027	$	6.591	$0.17	6.77
Mar	2024	6.483	$	0.027	$	6.510	$0.17	6.68
Apr	2024	6.402	$	0.104	$	6.506	$0.17	6.68
May	2024	6.402	$	0.103	$	6.505	$0.17	6.68
Jun	2024	6.564	$	0.103	$	6.667	$0.18	6.84
Jul	2024	6.726	$	0.104	$	6.830	$0.18	7.01
Aug	2024	6.888	$	0.104	$	6.992	$0.18	7.18
Sep	2024	6.807	$	0.104	$	6.911	$0.18	7.09
Oct	2024	6.807	$	0.104	$	6.911	$0.18	7.09
Nov	2024	7.212	$	0.034	$	7.246	$0.19	7.44
Dec	2024	7.618	$	0.022	$	7.639	$0.20	7.84
Jan	2025	6.738	$	0.027	$	6.764	$0.18	6.94
Feb	2025	6.822	$	0.027	$	6.848	$0.18	7.03
Mar	2025	6.738	$	0.027	$	6.764	$0.18	6.94
Apr	2025	6.653	$	0.104	$	6.757	$0.18	6.94
May	2025	6.653	$	0.103	$	6.757	$0.18	6.94
Jun	2025	6.822	$	0.103	$	6.925	$0.18	7.11
Jul	2025	6.990	$	0.104	$	7.094	$0.19	7.28
Aug	2025	7.159	$	0.104	$	7.262	$0.19	7.45
Sep	2025	7.074	$	0.104	$	7.178	$0.19	7.37
Oct	2025	7.074	$	0.104	$	7.178	$0.19	7.37
Nov	2025	7.496	$	0.034	$	7.529	$0.20	7.73
Dec	2025	7.917	$	0.022	$	7.938	$0.21	8.15
Jan	2026	6.999	$	0.027	$	7.025	$0.19	7.21
Feb	2026	7.086	$	0.027	$	7.113	$0.19	7.30
Mar	2026	6.999	$	0.027	$	7.025	$0.19	7.21
Apr	2026	6.911	$	0.104	$	7.015	$0.19	7.20
May	2026	6.911	$	0.103	$	7.014	$0.19	7.20

Jun	2026	7.086	$	0.103	$	7.189	$0.19	7.38
Jul	2026	7.261	$	0.104	$	7.365	$0.19	7.56
Aug	2026	7.436	$	0.104	$	7.540	$0.20	7.74
Sep	2026	7.349	$	0.104	$	7.452	$0.20	7.65
Oct	2026	7.349	$	0.104	$	7.453	$0.20	7.65
Nov	2026	7.786	$	0.034	$	7.820	$0.20	8.02
Dec	2026	8.223	$	0.022	$	8.245	$0.21	8.46
Jan	2027	7.267	$	0.027	$	7.294	$0.19	7.49
Feb	2027	7.358	$	0.027	$	7.385	$0.19	7.58
Mar	2027	7.267	$	0.027	$	7.294	$0.19	7.49
Apr	2027	7.177	$	0.104	$	7.280	$0.19	7.47
May	2027	7.177	$	0.103	$	7.280	$0.19	7.47
Jun	2027	7.358	$	0.103	$	7.462	$0.20	7.66
Jul	2027	7.540	$	0.104	$	7.643	$0.20	7.84
Aug	2027	7.722	$	0.104	$	7.825	$0.20	8.03
Sep	2027	7.631	$	0.104	$	7.734	$0.20	7.94
Oct	2027	7.631	$	0.104	$	7.735	$0.20	7.94
Nov	2027	8.085	$	0.034	$	8.119	$0.21	8.33
Dec	2027	8.539	$	0.022	$	8.561	$0.22	8.78
Jan	2028	7.557	$	0.027	$	7.583	$0.20	7.78
Feb	2028	7.651	$	0.027	$	7.677	$0.20	7.88
Mar	2028	7.557	$	0.027	$	7.583	$0.20	7.78
Apr	2028	7.462	$	0.104	$	7.566	$0.20	7.76
May	2028	7.462	$	0.103	$	7.565	$0.20	7.76
Jun	2028	7.651	$	0.103	$	7.754	$0.20	7.96
Jul	2028	7.840	$	0.104	$	7.944	$0.21	8.15
Aug	2028	8.029	$	0.104	$	8.132	$0.21	8.34
Sep	2028	7.934	$	0.104	$	8.038	$0.21	8.25
Oct	2028	7.934	$	0.104	$	8.038	$0.21	8.25
Nov	2028	8.407	$	0.034	$	8.440	$0.22	8.66
Dec	2028	8.879	$	0.022	$	8.901	$0.23	9.13
Jan	2029	7.828	$	0.027	$	7.855	$0.21	8.06
Feb	2029	7.926	$	0.027	$	7.952	$0.21	8.16
Mar	2029	7.828	$	0.027	$	7.855	$0.21	8.06
Apr	2029	7.730	$	0.104	$	7.834	$0.20	8.04
May	2029	7.730	$	0.103	$	7.833	$0.20	8.04
Jun	2029	7.926	$	0.103	$	8.029	$0.21	8.24
Jul	2029	8.122	$	0.104	$	8.225	$0.21	8.44
Aug	2029	8.317	$	0.104	$	8.421	$0.22	8.64
Sep	2029	8.219	$	0.104	$	8.323	$0.22	8.54
Oct	2029	8.219	$	0.104	$	8.323	$0.22	8.54
Nov	2029	8.709	$	0.034	$	8.742	$0.23	8.97
Dec	2029	9.198	$	0.022	$	9.220	$0.24	9.46
Jan	2030	8.120	$	0.027	$	8.147	$0.21	8.36
Feb	2030	8.222	$	0.027	$	8.248	$0.22	8.46
Mar	2030	8.120	$	0.027	$	8.147	$0.21	8.36
Apr	2030	8.019	$	0.104	$	8.122	$0.21	8.33

May	2030	8.019	$	0.103	$	8.122	$0.21	8.33
Jun	2030	8.222	$	0.103	$	8.325	$0.22	8.54
Jul	2030	8.425	$	0.104	$	8.528	$0.22	8.75
Aug	2030	8.628	$	0.104	$	8.731	$0.23	8.96
Sep	2030	8.526	$	0.104	$	8.630	$0.22	8.85
Oct	2030	8.526	$	0.104	$	8.630	$0.22	8.85
Nov	2030	9.034	$	0.034	$	9.067	$0.23	9.30
Dec	2030	9.541	$	0.022	$	9.563	$0.25	9.81
Jan	2031	8.420	$	0.027	$	8.447	$0.22	8.67
Feb	2031	8.525	$	0.027	$	8.552	$0.22	8.77
Mar	2031	8.420	$	0.027	$	8.447	$0.22	8.67
Apr	2031	8.315	$	0.104	$	8.418	$0.22	8.64
May	2031	8.315	$	0.103	$	8.418	$0.22	8.64
Jun	2031	8.525	$	0.103	$	8.629	$0.22	8.85
Jul	2031	8.736	$	0.104	$	8.839	$0.23	9.07
Aug	2031	8.946	$	0.104	$	9.050	$0.23	9.28
Sep	2031	8.841	$	0.104	$	8.945	$0.23	9.18
Oct	2031	8.841	$	0.104	$	8.945	$0.23	9.18
Nov	2031	9.367	$	0.034	$	9.401	$0.24	9.64
Dec	2031	9.894	$	0.022	$	9.915	$0.26	10.17
Jan	2032	8.800	$	0.027	$	8.827	$0.23	9.06
Feb	2032	8.910	$	0.027	$	8.936	$0.23	9.17
Mar	2032	8.800	$	0.027	$	8.827	$0.23	9.06
Apr	2032	8.690	$	0.104	$	8.794	$0.23	9.02
May	2032	8.690	$	0.103	$	8.793	$0.23	9.02
Jun	2032	8.910	$	0.103	$	9.013	$0.23	9.25
Jul	2032	9.130	$	0.104	$	9.233	$0.24	9.47
Aug	2032	9.350	$	0.104	$	9.453	$0.24	9.70
Sep	2032	9.240	$	0.104	$	9.343	$0.24	9.58
Oct	2032	9.240	$	0.104	$	9.344	$0.24	9.59
Nov	2032	9.790	$	0.034	$	9.823	$0.25	10.08
Dec	2032	10.340	$	0.022	$	10.362	$0.27	10.63
Jan	2033	9.122	$	0.027	$	9.149	$0.24	9.39
Feb	2033	9.236	$	0.027	$	9.263	$0.24	9.50
Mar	2033	9.122	$	0.027	$	9.149	$0.24	9.39
Apr	2033	9.008	$	0.104	$	9.112	$0.24	9.35
May	2033	9.008	$	0.103	$	9.112	$0.24	9.35
Jun	2033	9.236	$	0.103	$	9.340	$0.24	9.58
Jul	2033	9.465	$	0.104	$	9.568	$0.25	9.82
Aug	2033	9.693	$	0.104	$	9.796	$0.25	10.05
Sep	2033	9.579	$	0.104	$	9.682	$0.25	9.93
Oct	2033	9.579	$	0.104	$	9.683	$0.25	9.93
Nov	2033	10.149	$	0.034	$	10.182	$0.26	10.44
Dec	2033	10.719	$	0.022	$	10.741	$0.28	11.02

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EXHIBIT NO. 29

DOCKET NO: 150043-EI

WITNESS:

PARTY:

DESCRIPTION:

DOCUMENTS: Proposed Stipulation of Issues

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150043-EI EXHIBIT: 29
PARTY: Staff
DESCRIPTION: Proposed Stipulation of Issues

Docket 150043 Proposed Stipulations

Issue 1: **Does DEF have a need for additional generation capacity prior to 2018?**

Proposed Type 2 Stipulation:

Yes, DEF has a need for additional generation capacity prior to 2018, as demonstrated in its testimony and exhibits in this docket.

Issue 2: **Is the acquisition of Calpine's Osprey Plant the most cost-effective way to meet DEF's generation need prior to 2018?**

Proposed Type 2 Stipulation:

Yes, the acquisition of the Osprey Plant is the most cost effective way to meet DEF's generation need prior to 2018, if the Osprey Plant acquisition is approved by the requisite regulatory authorities in accordance with the APA.

Issue 3: **Does the Asset Purchase and Sale Agreement for the Osprey Plant contain adequate provisions to protect DEF's customers?**

Stipulation:

- DEF entered into an Asset Purchase and Sale Agreement ("APA") with Osprey Energy Center, LLC as the assignee of Calpine Construction Finance Company, L.P. ("Calpine") to purchase Calpine's Osprey Plant.
- The APA contains provisions that are intended to protect DEF's customers if certain contingencies occur related to the proposed acquisition of the Osprey Plant.
- Unless mutually agreed by the Stipulating Parties, the parties agree that DEF must strictly enforce all of the provisions of the APA, and DEF agrees that it will strictly enforce those provisions.
- DEF agrees that it will not and cannot use cost savings that may be realized in integrating the Osprey Plant into DEF's system, including transmission costs, to diminish or do away with any of the provisions, protections, or limitations contained in the APA.
- DEF agrees that only reasonable and prudent costs will be recovered through the GBRA mechanism and that DEF bears the burden of proof regarding prudence. As part of this stipulation, DEF agrees that the "extraordinary circumstances standard" found in F.A.C. Rule 25-22.082(15) applies to this transaction, as if DEF had selected the self-build option.

Issue 4: **If the Osprey Plant cannot be acquired under the terms and conditions of the Asset Purchase and Sale Agreement, is construction of the DEF Suwannee Generation Project the next most cost-effective way to meet DEF's generation need prior to 2018?**

Stipulation:

The Parties agree that if DEF cannot acquire the Osprey Plant, construction of the Suwannee Simple Cycle Project is the next most cost-effective alternative, and that DEF bears the burden of demonstrating that only reasonable and prudent costs for that project are recovered in rates.

Issue 5: **Given the resolution of the foregoing issues, how and when may DEF request recovery of the final costs for the Osprey Plant acquisition or the Suwannee Simple Cycle Project?**

Stipulation:

Pursuant to Paragraph 16 of the Revised and Restated Stipulation and Settlement Agreement ("RRSSA"), DEF may request cost recovery closer in time to the in-service date of the proposed generation resource. At that time, DEF can request recovery of the actual (or nearly final estimated or projected) costs incurred to place the resources in service on a reasonable time frame in advance of the actual in-service date, subject to the applicable burden(s) of proof referenced in the stipulations to Issues 3 and 4 above. Cost recovery may not occur until the resources are actually in service.