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FPSC - COMMISSION CLERK

Docket Nos. 140110-EI through 140111-EI
Comprehensive Exhibit List for Entry into Hearing Record for the Hearing Held on 8/26-27/14

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF				
1		Exhibit List	Comprehensive Exhibit List	
DUKE ENERGY FLORIDA, INC. – (DIRECT)				
2	Mark E. Landseidel	MEL-1 **(140110-EI)**	A preliminary aerial site plan of the Citrus County Combined Cycle Power Plant site	
3	Mark E. Landseidel	MEL-2 **(140110-EI)**	The preliminary general arrangement of the Citrus County Combined Cycle Power Plant at the Citrus County site	
4	Mark E. Landseidel	MEL-3 **(140110-EI)**	A copy of the Sargent & Lundy Consulting LLC Citrus County Combined Cycle Station Risk Analysis for Single Fuel Operation	
5	Mark E. Landseidel	MEL-4 **(140110-EI)**	A table of the major cost items for the Citrus County Combined Cycle Power Plant project	
6	Mark E. Landseidel	MEL-5 **(140110-EI)**	The projected schedule and key milestones for completion of the Citrus County Combined Cycle Power Plant project	
7	Mark E. Landseidel	MEL-1 **(140111-EI)**	A map showing the location of the Suwannee power plant site in Suwannee County, Florida	
8	Mark E. Landseidel	MEL-2 **(140111-EI)**	The preliminary layout of the Suwannee Simple Cycle project at the Suwannee power plant site	

9	Mark E. Landseidel	MEL-3 **(140111-EI)**	An itemization of the major cost items for the Suwannee Simple Cycle project	
10	Mark E. Landseidel	MEL-4 **(140111-EI)**	The projected schedule for completion of the Suwannee Simple Cycle project	
11	Mark E. Landseidel	MEL-5 **(140111-EI)**	A map showing the location of the Hines Chillers Power Uprate project in Polk County, Florida	
12	Mark E. Landseidel	MEL-6 **(140111-EI)**	The preliminary layout of the Hines Chillers Power Uprate project equipment and facilities located at the Hines Energy Complex in Polk County, Florida	
13	Mark E. Landseidel	MEL-7 **(140111-EI)**	An itemization of the major cost items for the Hines Chillers Power Uprate project	
14	Mark E. Landseidel	MEL-8 **(140111-EI)**	The projected schedule for completion of the Hines Chillers Power Uprate project	
15	Amy Dierolf	AD-1 **(140110-EI)**	A list of the permits or licenses DEF will obtain for the Citrus County Combined Cycle power plant	
16	Amy Dierolf	AD-2 **(140110-EI)**	A copy of the estimated schedule for submittal and approval of the SCA for the Citrus County Combined Cycle Power Plant	
17	Jeffrey Patton	JP-1 **(140110-EI)**	A map of the natural gas supply pipelines serving the State of Florida including the Sabal Trail Transmission LLC ("Sabal Trail") pipeline project	
18	Jeffrey Patton	JP-2 **(140110-EI)**	A map of the gas pipeline interconnection between Sabal Trail and the Citrus County Combined Cycle Plant and the interconnections between Sabal Trail and the FGT pipeline in Suwannee County and Citrus County, Florida	

19	Jeffrey Patton	JP-3 **(140110-EI)**	A map of the gas supply access at Transco Station 85 provided by Sabal Trail	
20	Jeffrey Patton	JP-4 **(140110-EI)**	A chart illustrating a forecast of United States dry natural gas production from the 2014 Annual Energy Outlook published by the Energy Information Administration	
21	Kevin Delehanty	KD-1 **(140110-EI)**	**CONFIDENTIAL** - A chart of the Company's base, high, and low natural gas price forecast	
22	Kevin Delehanty	KD-2 **(140110-EI)**	**CONFIDENTIAL** - A chart of the Company's base natural gas price forecast and other industry natural gas price forecasts	
23	Kevin Delehanty	KD-3 **(140110-EI)**	United States Energy Information Administration Map of major North American shale basins	
24	Kevin Delehanty	KD-4 **(140110-EI)**	United States Potential Gas Committee chart of Total Potential Resources	
25	Kevin Delehanty	KD-1 **(140111-EI)**	**CONFIDENTIAL** - A chart of the Company's base, high, and low natural gas price forecast	
26	Kevin Delehanty	KD-2 **(140111-EI)**	**CONFIDENTIAL** - A chart of the Company's base natural gas price forecast and other industry natural gas price forecasts	
27	Kevin Delehanty	KD-3 **(140111-EI)**	United States Energy Information Administration Map of major North American shale basins	
28	Kevin Delehanty	KD-4 **(140111-EI)**	United States Potential Gas Committee chart of Total Potential Resources	

29	Ed Scott	ES-1 **(140110-EI)**	A copy of the Florida Reliability Coordinating Council ("FRCC") Evaluation of Transmission Impact of the Environmental Protection Agency's Mercury and Air Toxics Standard -- Transmission Impact Study for Shutdown of Crystal River Units 1 & 2 with retirement of Crystal River Unit 3	
30	Ed Scott	ES-2 **(140110-EI)**	**CONFIDENTIAL** - transmission groups evaluated in the Company's transmission screening studies of the 2018 RFP proposals	
31	Ed Scott	ES-3 **(140110-EI)**	**CONFIDENTIAL** - description of the transmission system upgrades, modifications, or additions and their costs for the transmission groups evaluated in the Company's transmission screening studies of the 2018 RFP proposals	
32	Ed Scott	ES-1 **(140111-EI)**	A map and graphic illustration of the transmission interconnections for the Suwannee Simple Cycle Project at the Suwannee power plant site	
33	Ed Scott	ES-2 **(140111-EI)**	A depiction of the existing Hines Energy Complex combined cycle power plant blocks and the existing transmission interconnections	

34	Ed Scott	ES-3 **(140111-EI)**	**CONFIDENTIAL** - A 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	
35	Alan S. Taylor	AST-1 **(140110-EI)**	Document No. 1, Resume of Alan S. Taylor **CONFIDENTIAL** - Document No. 2, Sedway Consulting's Independent Evaluation Report.	
36	Julie Solomon	JS-1 **(140111-EI)**	A copy of Julie Solomon's curriculum vitae	Withdrawn
37	Julie Solomon	JS-2 **(140111-EI)**	A schematic showing DEF's Balancing Authority Area ("BAA") and other BAAs in the Florida Reliability Coordinating Council	Withdrawn
38	Julie Solomon	JS-3 **(140111-EI)**	Sample Herfindahl - Hirschman Index ("HHI") calculations of market concentration	Withdrawn
39	Julie Solomon	JS-4 **(140111-EI)**	A table depicting the metrics FERC uses to define market concentration and acceptable levels of HHI changes under the Competitive Analysis Screen	Withdrawn
40	Julie Solomon	JS-5 **(140111-EI)**	A table of the ten periods that are evaluated in the Competitive Analysis Screen	Withdrawn
41	Julie Solomon	JS-6 **(140111-EI)**	A table of the "Available Economic Capacity ("AEC") calculations derived for DEF in the competitive Analysis Screen evaluation	Withdrawn

42	Julie Solomon	JS-7 **(140111-EI)**	A table of the AEC calculations derived for DEF with a ten percent increase in the market price	Withdrawn
43	Julie Solomon	JS-8 **(140111-EI)**	A table summarizing the differences between the AEC for DEF from Exhibit No. ___ (JS-6) and Exhibit No. ___ (JS-7)	Withdrawn
44	Julie Solomon	JS-9 **(140111-EI)**	Results of the Competitive Analysis Screen for potential Acquisition 1	Withdrawn
45	Julie Solomon	JS-10 **(140111-EI)**	Results of the Competitive Analysis Screen for potential Acquisition 2	Withdrawn
46	Julie Solomon	JS-11 **(140111-EI)**	Results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 1	Withdrawn
47	Julie Solomon	JS-12 **(140111-EI)**	Results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 2	
48	Benjamin M.H. Borsch	BMHB-1 **(140110)**	**CONFIDENTIAL -** The Company's Need Study for the Citrus County Combined Cycle Power Plant.	
49	Benjamin M.H. Borsch	BMHB-2 **(140110)**	The Company's April 2014 Ten Year Site Plan ("TYSP")	
50	Benjamin M.H. Borsch	BMHB-3 **(140110)**	DEF's projected summer peak load growth and Reserve Margins with and without additional generation resources through 2018	
51	Benjamin M.H. Borsch	BMHB-4 **(140110)**	DEF's projected net energy for load growth on DEF's system	
52	Benjamin M.H. Borsch	BMHB-5 **(140110)**	A comparison of the cost efficiency of commercially available generation technologies including combined cycle generation technology	

53	Benjamin M.H. Borsch	BMHB-6 **(140110)**	A map of the location of unconventional shale gas developments and major gas pipelines in the Southeast United States	
54	Benjamin M.H. Borsch	BMHB-7 **(140110)**	A chart of the recent, current, and future production from both conventional and unconventional North American gas supply resources	
55	Benjamin M.H. Borsch	BMHB-8 **(140110)**	A map showing the location of the Sabal Trail natural gas pipeline and the other natural gas pipelines into the State of Florida	
56	Benjamin M.H. Borsch	BMHB-9 **(140110)**	A flow chart of the 2018 RFP evaluation process	
57	Benjamin M.H. Borsch	BMHB-10 **(140110)**	A table of the 2018 RFP Threshold Requirements	
58	Benjamin M.H. Borsch	BMHB-11 **(140110)**	A table of the 2018 Minimum Technical Requirements	
59	Benjamin M.H. Borsch	BMHB-12 **(140110)**	A table of the 2018 RFP bidder proposal resource scenarios evaluated in the Company's 2018 RFP evaluation process	
60	Benjamin M.H. Borsch	BMHB-13 **(140110)**	A table of the results of the Company's Initial Detailed Evaluation of the 2018 RFP bidder proposal resource scenarios	
61	Benjamin M.H. Borsch	BMHB-14 **(140110)**	A table of the results of the Company's Detailed Evaluation of the 2018 RFP bidder proposal resource scenarios and the Company's sensitivity analyses in its 2018 RFP evaluation	

62	Benjamin M.H. Borsch	BMHB-1 **(140111)**	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")	
63	Benjamin M.H. Borsch	BMHB-2 **(140111)**	The Company's current, April 2014 Ten Year Site Plan ("TYSP")	
64	Benjamin M.H. Borsch	BMHB-3 **(140111)**	The Company's near-term summer and winter load forecast	
65	Benjamin M.H. Borsch	BMHB-4 **(140111)**	The Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017	
66	Benjamin M.H. Borsch	BMHB-5 **(140111)**	The Company's forecast of physical and dispatchable demand-side resource reserves through the summers of 2016 and 2017	
67	Benjamin M.H. Borsch	BMHB-6 **(140111)**	The generation options evaluated to contribute to the Company's capacity needs in the summers of 2016 and 2017	
68	Benjamin M.H. Borsch	BMHB-7 **(140111)**	**CONFIDENTIAL** - A chart of the supply-side generation proposals evaluated by the Company to meet its capacity needs in the summers of 2016 and 2017	

69	Benjamin M.H. Borsch	BMHB-8 **(140111)**	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	Withdrawn
70	Benjamin M.H. Borsch	BMHB-9 **(140111)**	The Company's cost sensitivity analysis results based on the initial detailed economic analysis	Withdrawn
71	Benjamin M.H. Borsch	BMHB-10 **(140111)**	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	Withdrawn
72	Benjamin M.H. Borsch	BMHB-11 **(140111)**	The Company's analysis of natural gas price and carbon cost ("CO2") sensitivities to the final detailed economic analyses	Withdrawn
CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)				
73	Paul J. Hibbard	PJH-1**(140110,~~140111~~)**	Curriculum vitae of Paul J. Hibbard	
74	Paul J. Hibbard	PJH-2 **(140110,~~140111~~)**	**CONFIDENTIAL** - Calpine LCOE Model Sources and Assumptions	
75	Paul J. Hibbard	PJH-3 **(140110,~~140111~~)**	**CONFIDENTIAL** - Levelized Cost of Electricity ($2014/MWh)	
76	Paul J. Hibbard	PJH-4 **(140110,~~140111~~)**	**CONFIDENTIAL** - Levelized Cost ($2014/MWh) by Capacity Factor 2015-2043	
77	Paul J. Hibbard	PJH-5 **(140110,~~140111~~)**	Growth in Total Energy Demand and Potential Energy Generation from Generic Combined Cycle Units	

78	Paul J. Hibbard	PJH-6 **(140110,~~140111~~)**	**CONFIDENTIAL** - Comparison of Osprey Capacity Factor and Starts, by Year, DEF Production Simulation Results, Scenario 5 Acquisition	
79	Paul J. Hibbard	PJH-7a7b **(140110,~~111~~)**	**CONFIDENTIAL** - Adjustments to Cumulative Present Value Revenue Requirements	
80	Paul J. Hibbard	PJH-8 **(140110,~~140111~~)**	**CONFIDENTIAL** - Emission Rates by Technology Carbon Dioxide (CO2) and Nitrogen Oxides (NOx)	
81	John L. Simpson	JS-1 **(140110, ~~140111~~)**	Resume' of John L. Simpson, P.E.	
82	John L. Simpson	JS-2 **(140110, ~~140111~~)**	Excerpts from FPL Ten Year Site Plan – Turkey Point Synchronous Condenser Operation	
83	David Hunger, Ph.D.	DH-1 **(140111-EI)**	Qualifications and Experience of David Hunger, Ph.D.	Withdrawn
NRG FLORIDA, LP – (DIRECT)				
84	Jeffry Pollock	JP-1 **(140110, 140111)**	Appearance List	
85	Jeffry Pollock	JP-2 **(140110, 140111)**	Load Growth Sensitivity	
86	Jeffry Pollock	JP-3 **(140110, 140111)**	Capacity Requirement Sensitivity	
87	Jeffry Pollock	JP-4 **(140110, 140111)**	2013 Settlement	
88	Jeffry Pollock	JP-5 **(140110, 140111)**	Bill Comparison – Winter 2014	
89	Jeffry Pollock	JP-6 **(140110, 140111)**	Bill Comparison – Summer 2013	

90	John F. Morris	JRM-1**(140110,140111)**	Experience and Qualifications of Dr. John R. Morris	Withdrawn
91	John F. Morris	JRM-2**(140110,140111)**	Revised DPT Results: Duke Contracts with NRG	Withdrawn
92	John F. Morris	JRM-3**(140110,140111)**	Revised DPT Results: Duke Builds, NRG Exits	Withdrawn
STAFF				
93		Staff's Exhibit 93 **(Docket No. 140110-EI)**	DEF's responses to Staff's First Set of Interrogatories, Nos. 1-43. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00001-00064]*	**Stipulated**
94		Staff's Exhibit 94 **(Docket No. 140110-EI)**	DEF's responses to Staff's Second Set of Interrogatories, Nos. 44-49. *[Bates Nos. 00065-00072]*	**Stipulated**
95		Staff's Exhibit 95 **(Docket No. 140110-EI)**	DEF's responses to Staff's Third Set of Interrogatories, Nos. 50-54. *[Bates Nos. 00073-00082]*	**Stipulated**
96		Staff's Exhibit 96 **(Docket No. 140110-EI)**	DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 55-56. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00083-00091]*	**Stipulated**
97		Staff's Exhibit 97 **(Docket No. 140110-EI)**	DEF's responses to Calpine's First Set of Interrogatories, Nos. 3, 4, 9. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00092-00098]*	**Stipulated**
98		Staff's Exhibit 98 **(Docket No. 140110-EI)**	DEF's responses to Calpine's Fourth Set of Interrogatories, Nos. 14-15 & DEF's Supplemental responses to Calphine's Fourth Set of Interrogatories, No. 14. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00099-00105]*	**Stipulated**

99		Staff's Exhibit 99 **(Docket No. 140110-EI)**	DEF's responses to OPC's First Set of Interrogatories, Nos. 1-3, 9, 11-12. *[Bates Nos. 00106-00121]*	**Stipulated**
100		Staff's Exhibit 100 **(Docket No. 140110-EI)**	DEF's responses to Staff's First Production of Documents, Nos. 2, 3, 5 (**Confidential FPSC Document No. 03725-14**). **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00122-00124]*	**Stipulated**
101		Staff's Exhibit 101 **(Docket No. 140111-EI)**	DEF's responses to Staff's First Set of Interrogatories, Nos. 1-29, 30 (revised), 31-55. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00125-00206]*	**Stipulated**
102		Staff's Exhibit 102 **(Docket No. 140111-EI)**	DEF's responses to Staff's Second Set of Interrogatories, Nos. 56-61. *[Bates Nos. 00207-00214]*	**Stipulated**
103		Staff's Exhibit 103 **(Docket No. 140111-EI)**	DEF's responses to Staff's Third Set of Interrogatories, Nos. 62-83. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00215-00244]*	**Stipulated**
104		Staff's Exhibit 104 **(Docket No. 140111-EI)**	DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 84-86. *[Bates Nos. 00245-00250]*	**Stipulated**
105		Staff's Exhibit 105 **(Docket No. 140111-EI)**	DEF's responses to Staff's Fifth Set of Interrogatories, Nos. 87-90. *[Bates Nos. 00251-00257]*	**Stipulated**
106		Staff's Exhibit 106 **(Docket No. 140111-EI)**	DEF's response to Staff's Sixth Set of Interrogatories, Nos. 91-93. *[Bates Nos. 00258-00264]*	**Stipulated**
107		Staff's Exhibit 107 **(Docket No. 140111-EI)**	DEF's responses to Calpine's First Set of Interrogatories, Nos. 4, 5 (supplemental), 8. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00265-00274]*	**Stipulated**
108		Staff's Exhibit 108 **(Docket No. 140111-EI)**	DEF's responses to Calpine's Second Set of Interrogatories, No. 10. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00275-00279]*	**Stipulated**

109		Staff's Exhibit 109 **(Docket No. 140111-EI)**	DEF's responses to Calpine's Third Set of Interrogatories, Nos. 12, 15. *[Bates Nos. 00280-00284]*	**Stipulated**
110		Staff's Exhibit 110 **(Docket No. 140111-EI)**	DEF's responses to Calpine's Fourth Set of Interrogatories, No. 18. *[Bates Nos. 00285-00288]*	**Stipulated**
111		Staff's Exhibit 111 **(Docket No. 140111-EI)**	DEF's responses to NRG's First Set of Interrogatories, Nos. 2-4, 6, 14, 18, 21, 23-25, 27, 35-36, 38, 63, 69-70, 76, 84, 100. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00289-00316]*	**Stipulated**
112		Staff's Exhibit 112 **(Docket No. 140111-EI)**	Calpine's responses to Staff's First Set of Interrogatories, Nos. 1-4. *[Bates Nos. 00317-00326]*	**Stipulated**
113		Staff's Exhibit 113 **(Docket No. 140111-EI)**	Calpine's responses to Staff's Second Set of Interrogatories, Nos. 5-6. *[Bates Nos. 00327-00333]*	**Stipulated**
114		Staff's Exhibit 114 **(Docket No. 140111-EI)**	NRG's responses to Staff's First Set of Interrogatories, Nos. 1-3. *[Bates Nos. 00334-00341]*	**Stipulated**
115		Staff's Exhibit 115 **(Docket No. 140111-EI)**	NRG's responses to Staff's Second Set of Interrogatories, No. 4. *[Bates Nos. 00342-00346]*	**Stipulated**
116		Staff's Exhibit 116 **(Docket No. 140111-EI)**	DEF's responses to Staff's First Production of Documents, Nos. 1-10. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00347-00351]*	**Stipulated**
117		Staff's Exhibit 117 **(Docket No. 140111-EI)**	DEF's responses to Staff's Third Production of Documents, Nos. 14-16. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00352-00354]*	**Stipulated**
118		Staff's Exhibit 118 **(Docket No. 140111-EI)**	DEF's responses to Staff's Fifth Production of Documents, Nos. 20-21. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00355-00356]*	**Stipulated**

119		Staff's Exhibit 119 **(Docket No. 140111-EI)**	DEF's Supplemental response to NRG's First Production of Documents, No. 8. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00357-00359]*	**Stipulated**
120		Staff's Exhibit 120 **(Docket No. 140111-EI)**	Calpine's responses to Staff's First Production of Documents, Nos. 1-2. **See also files contained on Staff Exhibit CD.** *[Bates Nos. 00360-00362]*	**Stipulated**
121		Staff's Exhibit 121 **(Docket No. 140111-EI)**	NRG's responses to Staff's Second Production of Documents, No. 2. **See also file contained on Staff Exhibit CD.** *[Bates Nos. 00363-00422]*	**Stipulated**
122		Staff's Exhibit 122 **(Docket No. 140111-EI)**	**CONFIDENTIAL** - Deposition & Exhibits of Benjamin M.H. Borsch, August 11, 2014. (**Confidential FPSC Document No. 04633-14**). **See also Late Filed Exhibits No. 4, 5, 6 contained on Staff Exhibit CD.** **<u>NOTE:</u>** Exhibit No. 3 will not be provided pursuant to an objection for admission by DEF. *[Bates No. 00423]*	**Stipulated**
DUKE ENERGY FLORIDA, INC. – (REBUTTAL)				
123	Ed Scott	ES-4 **(140111-EI)**	The estimated cost for firm Point to Point (PTP") transmission reservation service with Tampa Electric Company ("TEC") to deliver the entire Calpine Osprey plant capacity and energy to the interface between the TEC and DEF system	Withdrawn
124	Ed Scott	ES-5 **(140111-EI)**	The estimated cost to wheel the 249MW of firm partial pass PTP transmission service that Calpine currently has with TEC to deliver 249MW of firm capacity and energy from the	Withdrawn

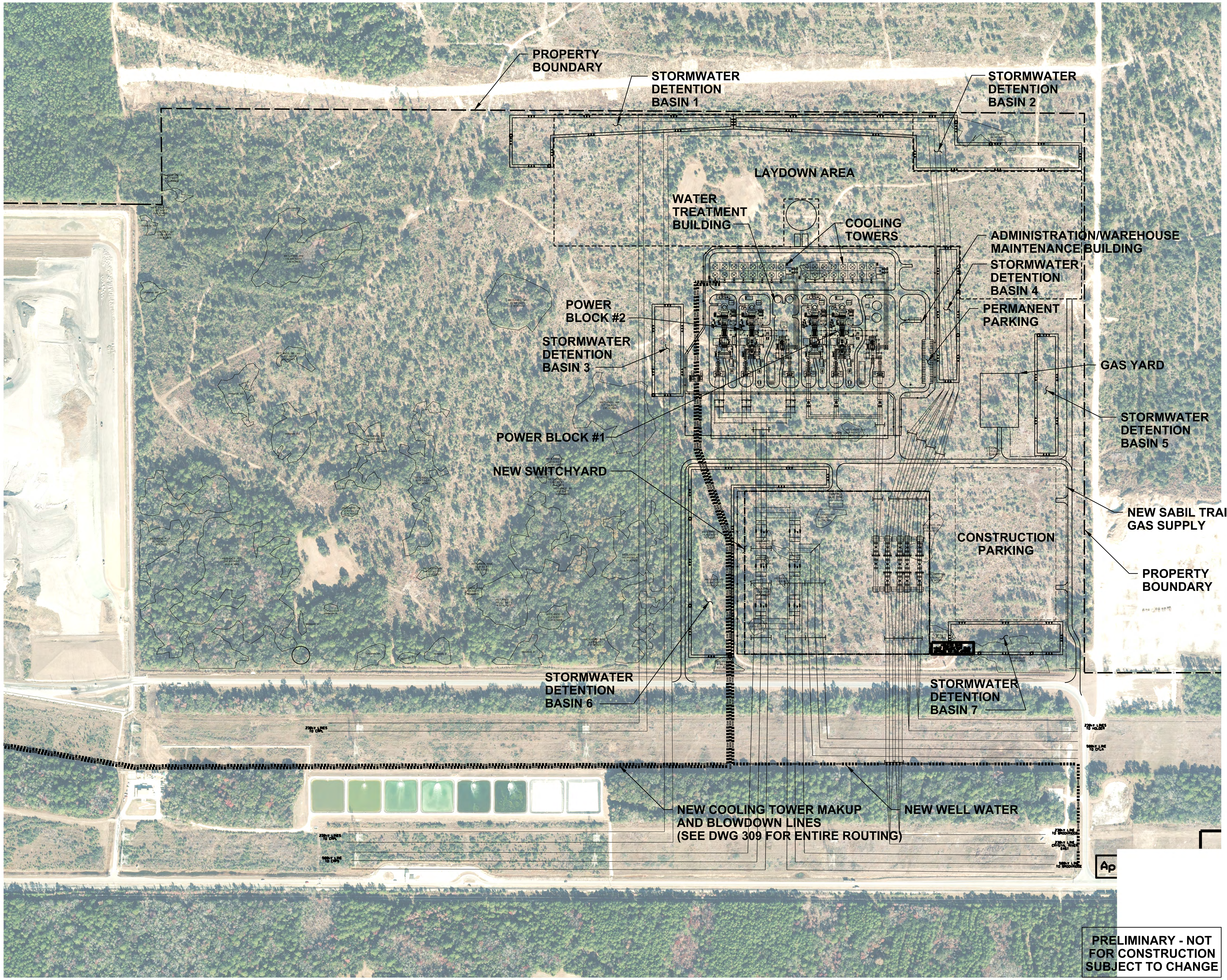
			Calpine Osprey plant to the interface between the TEC and DEF system.	
125	Benjamin M.H. Borsch	BMHB-15 **(140110)**	DEF's load forecasts	
126	Benjamin M.H. Borsch	BMHB-16 **(140110)**	DEF's analysis of the costs and benefits of deferring the Citrus County Combined Cycle Power Plant one year and continuing to operate its oldest, coal-fired steam generation units, Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") another year, to 2019	
127	Benjamin M.H. Borsch	BMHB-12 **(140111)**	**CONFIDENTIAL** - A composite exhibit of the written communications between DEF and NRG between late May 2014 and early July 2014	Withdrawn
128	Benjamin M.H. Borsch	BMHB-13 **(140111)**	**CONFIDENTIAL** - A composite exhibit of the written communications between DEF and Calpine between late May 2014 and early July 2014	
129	Benjamin M.H. Borsch	BMHB-14 **(140111)**	**CONFIDENTIAL** - NRG's final and best offer to sell its plant to DEF	Withdrawn
130	Benjamin M.H. Borsch	BMHB-15 **(140111)**	**CONFIDENTIAL** - DEF's evaluation of NRG's final and best offer to sell its plant to DEF	Withdrawn
131	Benjamin M.H. Borsch	BMHB-16 **(140111)**	**CONFIDENTIAL** - Calpine's June 16, 2014 final and best offer to sell its plant to DEF	
132	Benjamin M.H. Borsch	BMHB-17 **(140111)**	**CONFIDENTIAL** - Calpine's July 3, 2014 final and best offer to sell its plant to DEF	
133	Benjamin M.H. Borsch	BMHB-18 **(140111)**	**CONFIDENTIAL** - DEF's evaluation of Calpine's July 3, 2014 final and best offer to sell its plant to DEF	
134	Benjamin M.H. Borsch	BMHB-19 **(140111)**	DEF's summary of similar capital projects to the Suwannee Simple Cycle Project	

135	Benjamin M.H. Borsch	BMHB-20 **(140111)**	DEF's load forecasts	

OTHER HEARING EXHIBITS

Exhibit Number	Witness	Party	Description	Moved In/Due Date of Late Filed
136	B. Borsch	OPC	2013 Excerpt Seminole Ten Year Site Plan	
137	B. Borsch	OPC	Seminole Electric Contract Excerpts	
138	B. Borsch	OPC	Citrus, Osprey Delay Scenario	
139	B. Borsch	PCS	Actual and Forecasted grow rates chart TYSP 2010-~~10~~15	
140	B. Borsch	PCS	Historic Percentage of summer net firm to average sys. Demand and adjusted summer net firm demand forecast	
141	B. Borsch	PCS	Excerpt of Duke's SEC 8-K Dated July, 2014	
142	B. Borsch	SACE	Duke Avoided Generation Assumptions	
143	B Borsch	SACE	2013 10 TYSP	
144	B. Borsch	SACE	Review of 2013 TYSP	
145	B. Borsch	FIPUG	Current Draft Air Permit	

MEL-1



no.	date	by	ckd	description
A	03/05/14	RNO		ISSUED FOR REVIEW
B	04/01/14	RNO		ISSUED FOR REVIEW
C	5/07/14	RNO		ISSUED FOR REVIEW

PRELIMINARY - NOT FOR CONSTRUCTION SUBJECT TO CHANGE

Burns & McDonnell
SINCE 1898
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

date: MARCH 3, 2014	detailed: R. OWENS
designed: R. OWENS	checked:

DUKE ENERGY

CITRUS COUNTY, FLORIDA

HOLCIM SITE
PROPERTY BOUNDARY SITE PLAN
4x2

project: 71404	contract:
drawing: CS303	rev.: -C
sheet	of sheets

file 71404CS303.DGN

M:\Duke\71404\CAD\CIVIL\Holcim Site\71404CS303.dgn

5/7/2014

MEL-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 3
PARTY: DUKE ENERGY FLORIDA, INC. –
(DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-2

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION
001	GAS TURBINE GENERATOR (GTG)
002	HEAT RECOVERY STEAM GENERATOR (HRSG)
003	HRSG STACK
004	CIRCULATING WATER PUMPS
005	GT GSU
006	UNIT AUX TRANSFORMER
007	COOLING TOWER
008	COOLING TOWER PDC
009	COOLING TOWER CHEMICAL FEED ENCLOSURE
010	NOT USED
011	DEMINERALIZED WATER TANK
012	SERVICE ENCLOSURE
013	ADMIN BUILDING / SHOP
014	WAREHOUSE
015	NOT USED
016	BOILER CHEMICAL FEED SYSTEM
017	FIRE PUMP ENCLOSURE
018	SEWAGE AEROBIC DIGESTOR (BELOW GRADE)
019	WATER TREATMENT SYSTEM
020	ST PT SURGE CUBICLE
021	AIR COMPRESSOR
022	INLET AIR FILTER (SEE NOTE 1)
023	H2 STORAGE WITH SUN SHADE

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION
024	MISC. DRAINS TANK
025	AUXILIARY COOLING WATER PUMP
026	AMMONIA STORAGE
027	GTG EXCITATION TRANSFORMER
028	AUX. BOILER
029	GTG ELECTRICAL ENCLOSURE
030	H2 TRUCK UNLOADING
031	NOT USED
032	LOADING DOCK
033	SANITARY LIFT STATION
034	COMPRESSED AIR TRIM COOLERS
035	TRUCK UNLOADING
036	NITROGEN STORAGE PAD
037	NOT USED
038	NOT USED
039	HRSG STAIRTOWER
040	PHOSPHATE FEED ENCLOSURE
041	EMERGENCY DIESEL GENERATOR
042	CEMS ENCLOSURE
043	FUEL GAS PERFORMANCE HEATER
044	CONDENSATE FILTER/POLISHER
045	HRSG BLOWDOWN TANK
046	WASTEWATER COLLECTION SUMP (BELOW GRD)

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION
047	CLOSED COOLING WATER PUMPS
048	CCW HEAD TANK (ON PIPE RACK)
049	CCW HEAT EXCHANGERS
050	HRSG PDC
051	GTG STARTING SYSTEM ELECTRICAL ENCLOSURE
052	HRSG ELEVATOR
053	BOILER FEED PUMPS
054	FUEL GAS COELESCING FILTER
055	CATALYST REMOVAL AREA
056	AMMONIA FORWARDING PUMPS
057	GTG MAIN CIRCUIT BREAKER
058	GTG EXCIT ELECTRICAL ENCLOSURE
059	GTG FUEL GAS ENCLOSURE
060	NOT USED
061	AMMONIA FLOW CONTROL
062	SAMPLE PANEL ENCLOSURE
063	NOT USED
064	NOT USED
065	GTG LUBE OIL UNIT
066	NOT USED
067	GTG CONTROL OIL UNIT
068	NOT USED
069	NOT USED

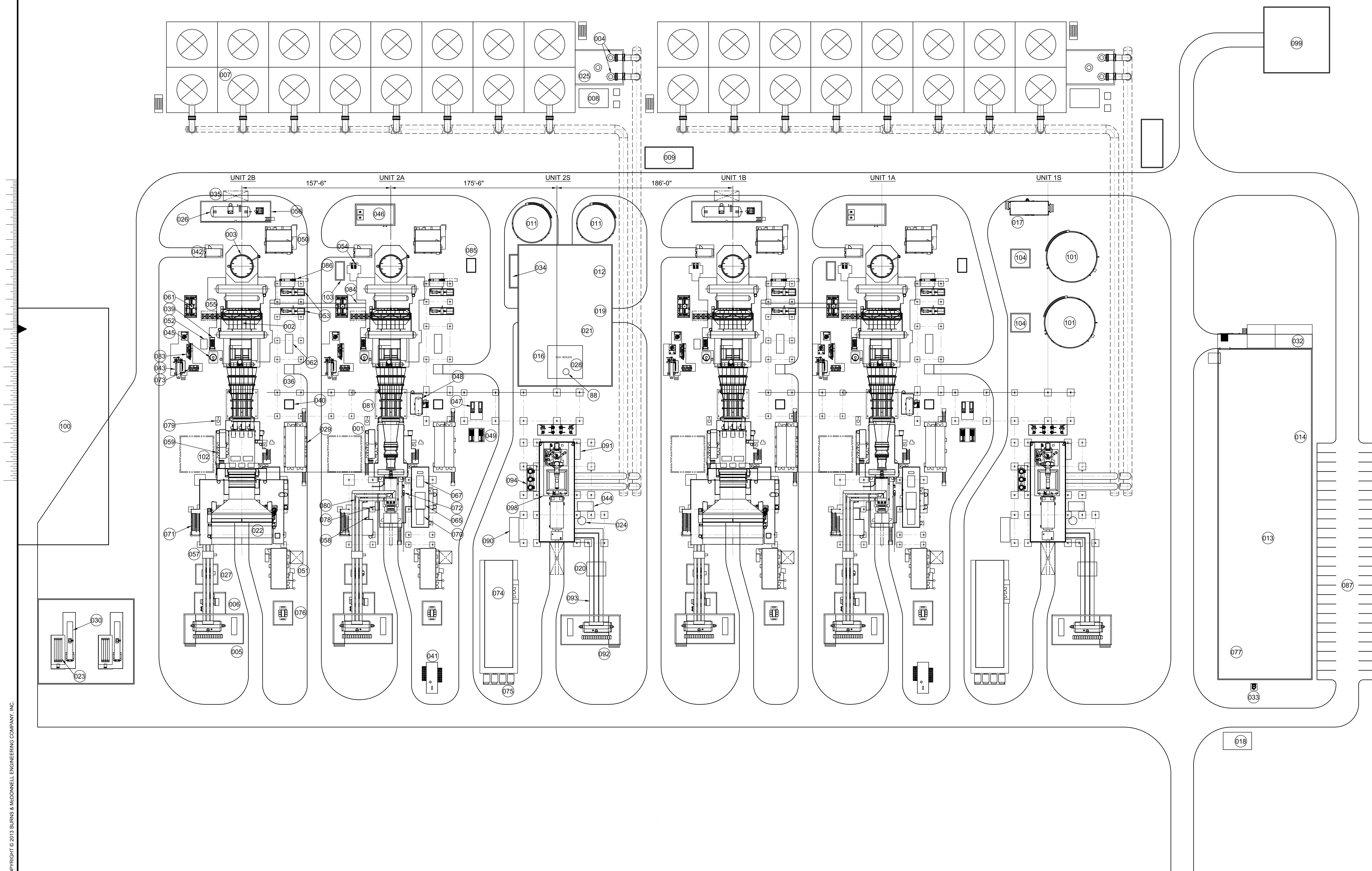
EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION
070	GTG AUXILIARY ENCLOSURE
071	GTG STAIR TOWER
072	GTG LOOP SEAL TANK
073	GTG FUEL GAS INLET FILTER
074	MAIN PDC
075	MAIN PDC SUS TRANSFORMERS
076	GTG STARTING SYSTEM TRANSFORMER
077	CONTROL ROOM
078	GTG NGR CUBICLE
079	GTG BLADE WASHING DRAINS TANK (BELOW GRADE)
080	GTG CO2 FIRE PROTECTION SKID
081	GTG BLADE WASH SKID
082	NOT USED
083	DUCT BURNER SKID
084	OVERHEAD WALKWAY PLATFORM
085	CO2 STORAGE ENCLOSURE
086	FGH AFTER COOLER
087	PARKING
088	AUX BOILER STACK
089	NOT USED
090	ST AREA STAIR TOWER
091	ST LUBE OIL SKID
092	ST GSU

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	
093	ST ISOPHASE BUS DUCT
094	CONDENSATE PUMPS
095	NOT USED
096	NOT USED
097	NOT USED
098	STEAM TURBINE ENCLOSURE
099	OIL STORAGE ENCLOSURE
100	STORMWATER POND
101	SERVICE / FIREWATER TANK
102	GTG CRANE PAD
103	FUEL GAS DEWPOINT HEATER
104	SERVICE WATER PUMPS

no.	date	by	ckd	description
A	10/26/13	MAA		ISSUED FOR REVIEW
B	11/15/13	MAA		ISSUED FOR BID
C	03/14/14	PS		ISSUED FOR REVIEW
D	04/28/14	PS		ISSUED FOR REVIEW



NOTES:
1. GTG INLET AIR FILTER NOT SHOWN ON UNIT 1A & 2A FOR CLARITY.

PRELIMINARY - NOT FOR CONSTRUCTION

NORTH

0 20' 40' 80'
SCALE IN FEET

Burns & McDonnell
SINCE 1898

date: MARCH 14, 2014
detailed: M. ATHERTON
designed: D. HOFRICHTER
checked:

DUKE ENERGY

CITRUS COUNTY, FLORIDA

HOLCIM SITE
GENERAL ARRANGEMENT

project: 71404
contract:

drawing: CCC00-GA-M-YD.00.PL-01 rev. C

sheet 1 of 1 sheets
file CC00-GA-YD.00.PL.01dwg

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 4
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-3

Citrus County Combined Cycle Station

Risk Analysis for Single Fuel Operation

Prepared for
Duke Energy Corporation

SL-012009
Revision 1
Project 12698-206
March 2014

DUKE ENERGY®

Prepared by

Sargent & Lundy LLC
Consulting
55 East Monroe Street • Chicago, IL 60603-5780 USA

Citrus County Combined Cycle Station
Risk Analysis for Single Fuel Operation

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March 2014

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Risk Analysis for Single Fuel Operation

CONTENTS

CONTENTS (cont.)

TABLES AND FIGURES

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
BACT	Best Available Control Technology
CC	Combined Cycle
CTG	Combustion turbine generator
DEP	Department of Environmental Protection
DO	Distillate oil
DOE	United States Department of Energy
FAC	Florida Administrative Code
FGT	Florida Gas Transmission (System)
FPL	Florida Power and Light
FRCC	Florida Reliability Coordinating Council
mmBtu	Million Btu
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NG	Natural gas
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation and maintenance
PSD	Prevention of Significant Deterioration
S&L	Sargent & Lundy LLC

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
scf	Standard cubic feet
SCR	Selective Catalytic Reduction
ULSD	Ultra-low sulfur diesel

EXECUTIVE SUMMARY

Sargent & Lundy (S&L) was retained by Duke Energy to analyze the risks and costs of firing the combustion turbine generators (CTG) of the Citrus County Combined Cycle Station using only a single source of fuel (natural gas) compared to providing that station with backup fuel capability (ultra-low sulfur diesel oil).

NATURAL GAS SUPPLY AND INFRASTRUCTURE

Two pipelines, Florida Gas Transmission and Gulfstream, currently provide 100% of the total natural gas supply capacity into the Florida Reliability Coordinating Council (FRCC). These pipelines enter Florida through Alabama and the Gulf Coast, respectively. A third main pipeline that will provide a significant natural gas supply to FRCC is in the planning stage. The pipeline, called the Sabal Trail Transmission Pipeline, will extend between southwest Alabama and Martin County, Florida, and is scheduled for completion in May 2017. As suggested by the *FRCC 2013 Load & Resource Reliability Assessment Report*,[1] this project will increase reliability throughout Florida by introducing a new supply source and will interconnect the proposed pipeline with the other two main pipelines.

NATURAL GAS CURTAILMENTS

S&L reviewed several sources to locate and identify gas supply disruptions in the southeastern states that may have affected the FRCC region. Among those, the NERC Special Reliability Assessment (May 2013) shows that natural gas supply curtailments have been caused by various factors. These include cold weather events and hurricanes.

- NERC indicates that cold weather events in 1983, 1989, 2003, 2006, 2008, 2010, and 2011 created disruptions in natural gas production, and that the 2003 and 2011 events caused curtailments. The 2003 event occurred in Texas when 5,500 MW of capacity was lost due to gas curtailments for 2–3 days. An estimated 3,200 MW was regained on back-up fuel oil. The 2011 event, also in Texas, curtailed about 14.8 billion cubic feet of gas over 5 days affecting natural gas supply to the southwestern U.S.
- Future supply disruptions due to hurricanes are expected to have less impact because much of the new production of natural gas supply is being obtained from inland shale deposits, which reduces the percentage of natural gas supply from hurricane prone areas.

[1] Florida Reliability Coordinating Council, *FRCC 2013 Load & Resource Reliability Assessment Report*, July 9, 2013.

Another documented cause of curtailment in the NERC Special Reliability Assessment report was a lightning strike in 1998 to the Perry Compressor Station in the Florida Gas Transmission (FGT) System. This event resulted in a reported 1.5 billion cubic feet per day curtailment, but electrical blackouts were avoided through demand-side management by requesting voluntary reduction in electrical consumption. Partial service to the natural gas lines resumed in approximately 3 days; the total impact lasted 5 days.

The infrequent occurrence of significant gas curtailment events due to cold weather, hurricanes, and other weather-related incidents suggests that the probability of occurrence is low, but also difficult to predict. Redundancies built into the system infrastructure, such as pipe looping, interconnections with other pipelines, and storage facilities, have been used to avoid extended supply disruptions and curtailments. Moreover, FRCC has developed an electrical generation shortage plan, which documents procedures to be used by Florida's electric utilities and governmental agencies for response to an energy emergency to increase region-wide reliability.

DUAL FUEL OPERATION

S&L conducted a review of the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database and a review of permits issued for combined-cycle combustion turbines in Florida to identify expected Best Available Control Technology (BACT) for new combined cycle combustion turbines. Recently permitted single and dual fuel-fired combined-cycle combustion turbines facility projects were permitted with similar combustion control and post-combustion control emissions technologies. For NO_X control, combined-cycle combustion turbine facilities were permitted with Dry Low-NO_X systems when firing natural gas, water injection systems when firing fuel oil, and post-combustion controls, specifically selective catalytic reduction (SCR) systems, to be used when firing natural gas and fuel oil.

Facilities firing diesel fuel oil will likely have a more challenging time demonstrating compliance with the recently updated 1-hour NO_2 and SO_2 National Ambient Air Quality Standards (NAAQS), 100 ppb and 75 ppb, respectively, especially during start-up, since NO_X and SO_2 emissions from firing diesel fuel oil tend to be higher than emissions from firing natural gas. There are many variables that are considered during the air quality impact modeling process, and analyses must be conducted on a case-by-case basis. In the case of dual fuel capability, obtaining an air quality permit will likely be more difficult due to the expected NAAQS compliance challenges.

S&L assessed the prevalence of backup fuel capability in combined cycle plants in FRCC. Forty combined cycle plants were identified, of which 23 (58%) have natural gas as primary fuel and diesel or distillate fuel oil as backup fuel, and 17 (43%) have natural gas as primary fuel but no backup fuel capability. On an installed capacity basis, about half the capacity has backup fuel capability. Furthermore, most of Duke Energy's plants in Florida have backup fuel capability.

SUMMARY

Given the infrequent occurrence of significant historical gas curtailment events and the expected system reliability increase from the Sabal Trail pipeline, the probability of occurrence of gas curtailments is very low. Redundancies built into the system infrastructure, such as pipe looping, interconnections with other pipelines, and storage facilities, have been used to avoid extended supply disruptions and curtailments.

Most of Duke Energy plants in Florida already have backup fuel capability. Additional dual fuel capabilities at the Citrus County Combined Cycle Station after the completion of the Sabal Trail pipeline and its interconnection with the FGT and Gulfstream pipelines would result in only a small incremental impact on system reliability. In addition, FRCC has developed an electrical generation shortage plan, which documents procedures to be used by Florida's electric utilities and governmental agencies for response to an energy emergency to increase region-wide reliability.

Last page of Executive Summary.

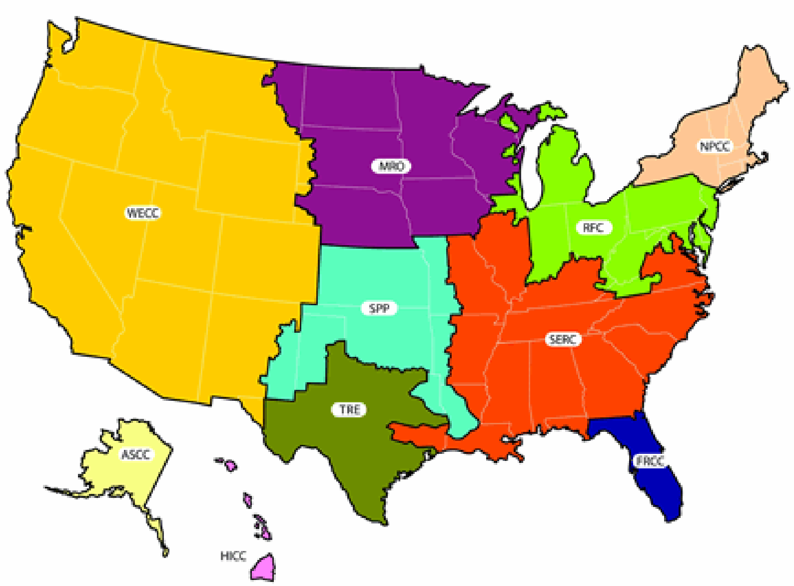
1. INTRODUCTION

This report presents an analysis of the risks and costs of firing the combustion turbine generators (CTG) of the Citrus County Combined Cycle Station using only a single source of fuel (natural gas) versus providing that station with backup fuel capability (ultra-low sulfur diesel oil).

Increased consumption of natural gas for power generation in the U.S. is a concern raised by the North American Electric Reliability Corporation (NERC), a not-for-profit entity whose mission is to ensure the reliability of the Bulk-Power System in North America. NERC conducts reliability assessments of the North American bulk power systems aiming to identify emerging risks and potential reliability problems for electricity production. NERC's assessments are often reviewed by regulators having decision-making responsibilities within the electric sector.

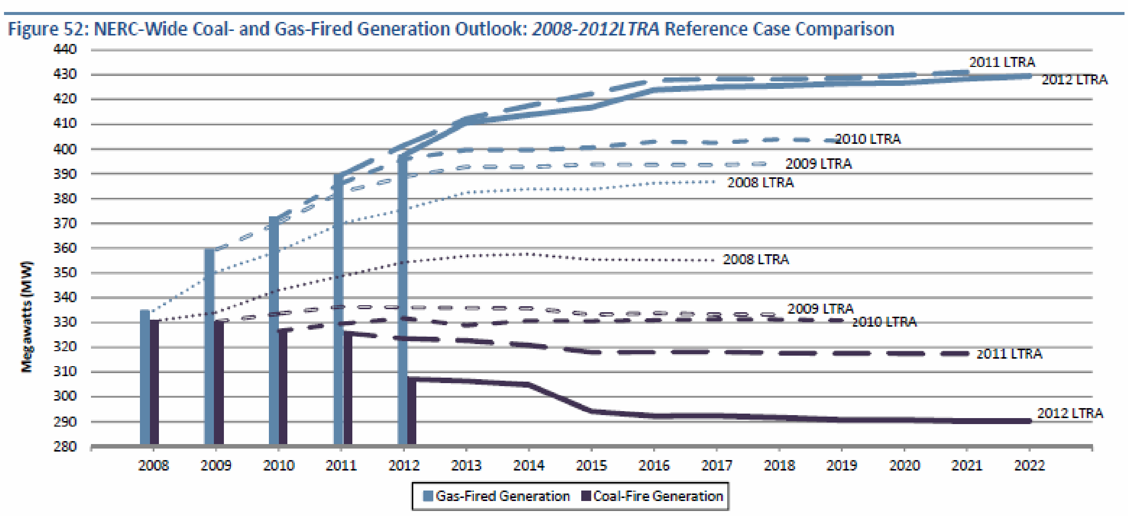
The Florida Reliability Coordinating Council (FRCC) is one of eight reliability regions NERC has established within the contiguous United States to focus reliability analysis on regional variables such as seasonal demand fluctuations, demand response procedures, resource capacity, etc. It covers the state of Florida except for the panhandle area served by Gulf Power Company (see Figure 1-1).

Figure 1-1 — North American Electric Reliability Corporation Regional Entities



Increased dependency on natural gas[2] is among potential high impact reliability risks identified for all the regional NERC entities. NERC projects that over the next ten years natural gas will be the most common fuel source for new electricity generation construction due to its affordability, low emissions, low capital cost of gas-fired plants, and short construction lead times of gas-fired plants relative to alternatives.[3] Figure 1-2 shows the annual projections for installed coal-fired and gas-fired capacity in NERC's Long-Term Reliability Outlook projections of 2008 through 2012, showing the disparity in expected growth between the two types of generation, with gas-fired generation projections growing year on year and coal transitioning from a projection of modest growth in the 2008 projection to a projection of substantial net retirements in the 2012 projection. NERC is concerned about increasing dependency of the bulk power supply system's reliance on natural gas, and the potentially serious effect that natural gas supply interruptions could have on bulk power supply reliability. Florida may be more susceptible to supply problems due to its peninsular geography and limited number of supply sources.

Figure 1-2 — NERC-Wide Coal and Gas Fired Generation Outlook



Source: NERC 2012 Long-Term Reliability Assessment, November 2012, p. 64. Ordinate is shown as MW in the original report but should have been labeled GW.

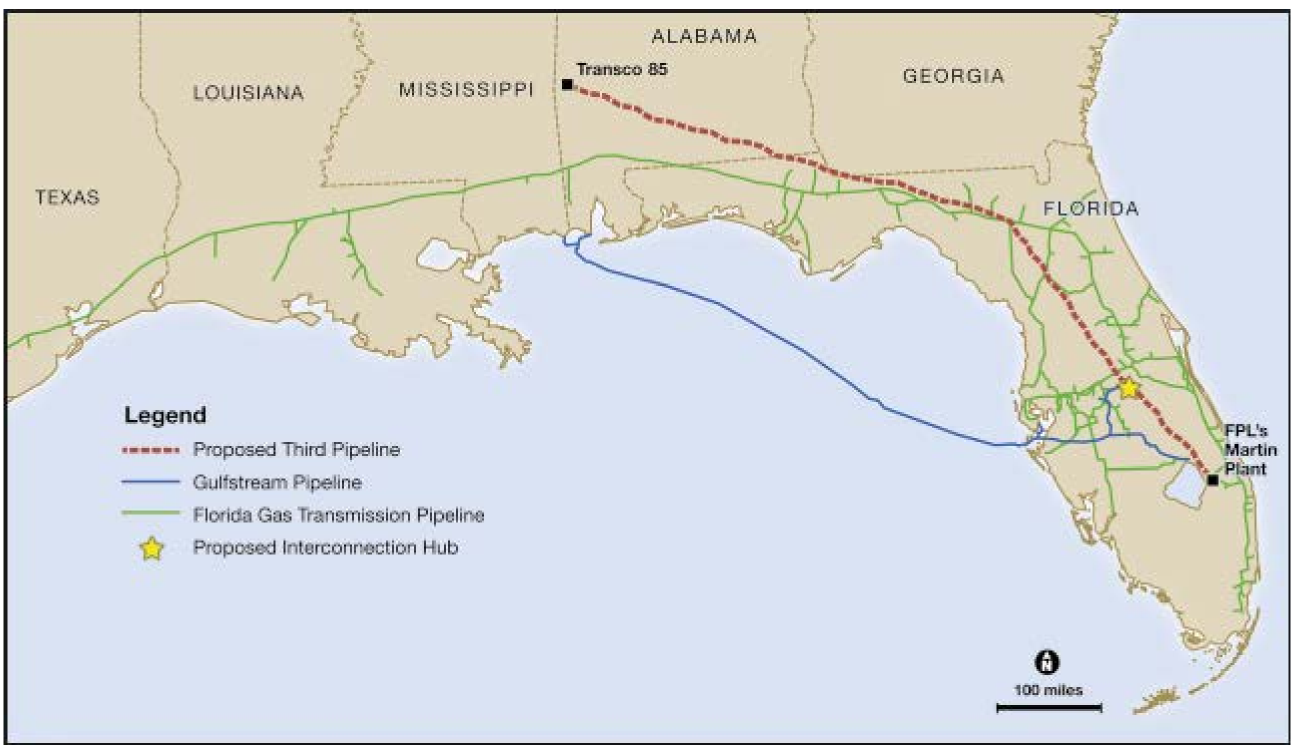
Last page of Section 1.

[2] NERC 2012 Long-Term Reliability Assessment November 2012, pp. 52 through 54.
[3] Figure 1 2, page 64 of above-cited NERC Report.

2. NATURAL GAS SUPPLY AND DEMAND IN FLORIDA

Natural gas is currently supplied to Florida via four pipelines. One of these (Gulf South pipeline) serves the Gulf Power region (Florida panhandle) and is not a factor in supply of the FRCC reliability region. The pipeline of the Southern Natural Gas Company supplies some gas to FRCC, but that fuel flows through the Florida Gas Transmission Company's pipeline and thus is not additive to the capacity of the two largest pipelines in supply to FRCC. Therefore the largest two pipelines, those of Florida Gas Transmission and Gulfstream, currently represent 100% of the total natural gas supply capacity into the FRCC (referred to in this section as the main pipelines). The two main pipelines enter Florida through Alabama and the Gulf Coast. The two minor pipelines supply natural gas primarily to markets outside of Florida; they do supply some natural gas to Florida, but via the larger pipelines. A third main pipeline, Sabal Trail Transmission Pipeline, is in the planning stage and will provide a significant natural gas supply to Florida. Routes of the existing two main pipelines and the planned future pipeline are shown in Figure 2-1.

Figure 2-1 — Routes of Natural Gas Supply Pipelines Serving Florida



The gas capacity supplying the FRCC region from the Gulfstream Pipeline and the Florida Gas Transmission Pipeline totals 4.329 billion cubic feet per day. Capacities of existing and planned pipelines serving Florida are shown in Table 2-1.

Table 2-1 — Florida Natural Gas Pipeline Capacity

Pipeline Owner	Length (miles)	Pipeline Capacity (billion ft^3/day)	Initial Service Year in Florida (2)	Primary Market
Florida Gas Transmission Company LLC	5,300	3.044	2001	Florida, Louisiana, and Alabama
Gulfstream Natural Gas System	745	1.285	2002	Florida
Southern Natural Gas Company	7,600	0.411 (1)	2007	Alabama, Georgia, Mississippi, and Louisiana. Capacity is not additive in supply of FRCC, however.
Gulf South Pipeline Company	7,240	0.190 (Note 1)	1998	Alabama, Louisiana, and Mississippi. Does not serve FRCC.
Total Existing Capacity Supplying FRCC		4.329		
Total Existing Capacity Supplying Florida		4.930		

(1) Southern Natural Gas and Gulf South pipelines do not represent independent supply capacity to FRCC. Gas to FRCC from Southern Natural Gas enters through the FGT pipeline, and the Gulf South pipeline services the panhandle area of Florida, which is outside of FRCC.

(2) Source: United States Department of Energy, Energy Information Administration – naturalgaspipelineprojects.xls

2.1 FLORIDA GAS TRANSMISSION PIPELINE

The Florida Gas Transmission Pipeline (shown in green in Figure 2-1) currently provides approximately 70% of the natural gas pipeline capacity serving FRCC. This pipeline is owned by Florida Gas Transmission Company, LLC and operated by Citrus Corporation. Citrus Corporation is a joint venture between Energy Transfer Partners and Kinder Morgan.[4] The Florida Gas Transmission Pipeline stretches a total of 5,300 miles from southeast Texas to southern Florida along the Gulf Coast region of the United States. The pipeline system operates and maintains over 70 interconnections[5] with major interstate and intrastate natural gas pipelines and has several storage connection points in eastern Mississippi as shown in Figure 2-2. These storage and interconnections help maintain sufficient natural gas supply during peak time periods, and increase reliability.

[4] Yahoo Finance: http://biz.yahoo.com/ic/113/113367.html
[5] Energy Transfer website: www.energytransfer.com/ops_interstate.aspx

Currently, firm transportation capacity on the Florida Gas Transmission Pipeline and on the Gulfstream Pipeline is approximately 96% subscribed on a term basis,[6] which is not adequate for future gas generation growth. Natural gas-fired combined-cycle generation requires firm transportation capacity on pipelines to support reliable full-load operation, particularly during peak periods. On June 1, 2013, The Florida Gas Transmission Company reported a total unsubscribed firm transportation capacity into the Florida Market Area of 123,500 mmBtu/day.

Figure 2-2 — Florida Gas Transmission Pipeline

Source: http://fgttransfer.energytransfer.com/ipost/FGT

2.2 GULFSTREAM PIPELINE

The Gulfstream Pipeline supplies natural gas only to Florida and currently provides approximately 30% of the natural gas pipeline capacity serving FRCC. This pipeline is owned and operated by Gulfstream Natural Gas System, LLC, which is a joint venture between Williams Partners L.P. and Spectra Energy. The Gulfstream Pipeline ranges in size from 16 inches to 36 inches and stretches 745 miles from the Mississippi-Alabama border through the Gulf of Mexico into Tampa Bay area and then extends via land to south central Florida (see Figure 2-3). The pipeline has three compressor stations with a total of 168,000 horsepower. The Gulfstream pipeline was placed into service in 2002 and is the first interstate pipeline to be routed under the Gulf of Mexico.

[6] Florida Reliability Coordinating Council, *FRCC 2013 Load & Resource Reliability Assessment Report*, July 9, 2013.

Figure 2-3 — Gulfstream Pipeline

Source: http://wp.gulfstreamgas.com/

The Gulfstream and FGT pipelines are interconnected in two places not far from Tampa, at Hardee and Osceola, with transfer capacities of 300,000 and 250,000 mmBtu/day, respectively. As mentioned previously, the Gulfstream firm transportation capacity is essentially fully subscribed. Only a small volume of firm transportation capacity is available in the winter months.[7] Since natural gas-fired combined-cycle generation requires firm transportation capacity on pipelines to support reliable full-load operation, particularly during peak periods, the Gulfstream pipeline is not adequate for future gas generation growth.

2.3 SABAL TRAIL TRANSMISSION PIPELINE

A planned pipeline will provide an estimated 1 billion cubic feet per year of natural gas capacity into Florida.[8] The project has been awarded to Sabal Trail Transmission, LLC, a joint venture between Spectra Energy and

[7] Florida Reliability Coordinating Council, *FRCC 2013 Load & Resource Reliability Assessment Report*, July 9, 2013.
[8] Spectra Energy Website: http://www.spectraenergy.com/

NextEra Energy, Inc. Additional natural gas capacity is very important to Florida because the existing pipelines are approaching full capacity and the future demand of natural gas is expected to increase at a steady rate.

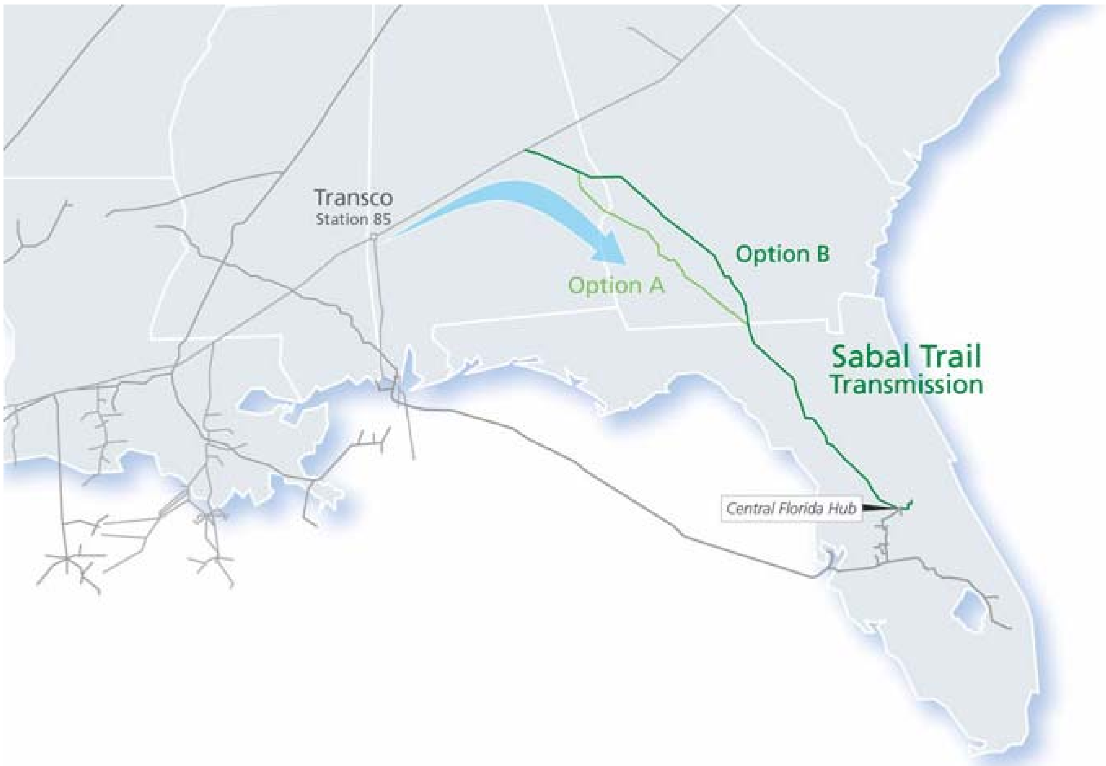
The proposed pipeline, called the Sabal Trail Transmission Pipeline, will extend between southwest Alabama and Martin County, Florida (see Figure 2-4). This project will increase reliability, diversity, and firm capacity throughout Florida by introducing a new supply source and by interconnecting with the other two main pipelines, FGT and Gulfstream.

The proposed project is part of two stages. The first stage consists of a stretch of approximately 465 miles of 36-inch diameter pipe from Alabama to a hub in central Florida. The second stage consists of installing approximately 126 miles of pipe from the central hub to a Florida Power and Light (FPL) plant in Martin County.[9]

The project is currently working through an extensive permitting process required on multiple levels, including the federal, state, and local, and is scheduled to begin construction in 2016 with project completion scheduled in May 2017.

[9] WGCU Southwest Florida News: http://news.wgcu.org/post/fpl-seeks-approval-600-miles-natural-gas-pipeline

Figure 2-4 — Sabal Trail Transmission Pipeline



Source: http://www.spectraenergy.com

2.4 CONCLUSIONS

One of the key findings in the FRCC 2013 Load & Resource Reliability Assessment Report issued July 9, 2013, was the following statement: "The natural gas pipeline capability is currently adequate; however, with limited infrastructure diversity and high dependence, adequacy could be impacted by the potential that future demand growth could exceed capacities or in the event of longer term pipeline outages or failures." The report further noted, "The FRCC, through its Fuel Reliability Working Group (FRWG), provides the administrative oversight of a Regional fuel reliability forum that assesses the interdependencies of fuel availability and electric reliability. Results of the most recent gas study indicated minimal risk to the reliability of the power system within the FRCC Region related to projected shorter term gas delivery disruptions." The report also stated, "As to future requirements, these existing natural gas pipelines into Florida are almost fully subscribed, though Florida's natural gas needs are expected to remain high in the coming years. To meet the high demand, the gas transportation infrastructure serving the state will also need to expand."

Last page of Section 2.

3. NATURAL GAS CURTAILMENTS AFFECTING FLORIDA

Several sources were reviewed to locate and identify gas supply disruptions in the southeastern states that may have affected the FRCC region. The sources reviewed to obtain this information are listed below.

- National Energy Technology Laboratory Electric Disturbance Events (OE-417) Annual Summaries
- NERC 2013 Special Reliability Assessment, dated May 2013
- NERC 2012 Long-Term Reliability Assessment, dated November 2012
- Posted Critical Notices on Gulfstream Natural Gas System website
- Posted Critical Notices on Florida Gas Transmission Pipeline website
- Personal interviews with personnel at Gulfstream Natural Gas System and Florida Gas Transmission Pipeline.

Natural gas supply curtailments documented within the NERC Special Reliability Assessment have been caused by various factors. Most recently in February of 2011, sustained freezing temperatures in southern Texas caused the moisture in the natural gas at the wellheads to freeze, blocking flow through pipelines. Icy roads prevented maintenance personnel from reaching the well heads to maintain them, and electrical blackouts during this period caused service interruptions in the natural gas compressor stations. The total curtailment impact of this event was 14.8 billion cubic feet over the course of five days primarily affecting the Transwestern Pipeline and El Paso Pipeline companies that supply natural gas to the southwestern United States.[10] Even though this event did not cause curtailment in Florida, the cold weather that occurred in Texas could just have easily affected the supply trunk lines into the Florida market.

Texas has had other cold-weather related production disruptions or curtailments before the 2011 event. NERC indicates that cold weather events in 1983, 1989, 2003, 2006, 2008, and 2010 created disruptions in natural gas production, and the 2003 event caused curtailments. The 2003 event occurred in Texas when 5,500 MW of capacity was lost due to gas curtailments for 2–3 days. An estimated 3,200 MW was regained on back-up fuel oil. There have been seven reported cold weather events over a 28-year span between 1983 and 2011 in Texas, all of which affected natural gas supplies to some extent, with two events causing curtailments. These indicate that although infrequent, the events and consequences do occur.

[10] North American Electric Reliability Corporation, "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," dated August 2011

Hurricanes are another frequent cause of natural gas supply disruptions. In a 13-year period, 1992 to 2010, a reported 21 hurricanes or tropical storms hit the Gulf Coast region and caused natural gas supply disruptions to some extent. The magnitude of the natural gas supply disruption over the 13-year time period as reported in the NERC Special Reliability Assessment report is shown in Table 3-1.

The Electric Disturbance Event (OE-417) Annual Summaries for years 2000 through 2013 reported by National Energy Technology Laboratory (NETL) were reviewed for disturbances in the FRCC region attributable to supply disruptions. Several reported incidents from Hurricane Katrina and Hurricane Rita in 2005 disrupted natural gas supplies or allotments, but the magnitudes of the disruptions were not reported.

Table 3-1 — Significant Gulf Coast Storms and Lost Gas Production

Year	Storms in Gulf	Category 3+ Storms in Gulf	Description	Estimated Gulf Gas Production Lost (Bcf)
1992	1	1	Andrew hit S. FL as a Cat 5 and LA as a Cat 3	N/A
1995	2	1	Erin hit E. FL as a Cat 1, crossed into gulf and hit FL panhandle as a Cat 2; Opal landed as a Cat 3 on FL panhandle	19
1997	1	0	Danny came across central gulf and LA tip and landed in Mobile Bay as Cat 1	
1998	1	0	Georges hit Cuba but was down to a Cat 1 when it hit MS	
1999	1	1	Bret hit S. TX as a Cat 3, Irene hit S. FL as a Cat 1	
2002	2	0	Isidore and Lili both Cat 1	76
2003	2	0	Tropical Storm Bill, Claudette Cat 1, and Erika	8
2004	2	2	Charlie Cat 4 hit SW FL and Ivan Cat 3 hit AL/FL border	196
2005	5	3	Cindy Cat 1 hit LA, Dennis Cat 3 hit FL panhandle, Katrina Cat 3 hit LA, and Rita Cat 3 hit TX/LA border	899
2007	0	0	Dean and Felix hit southern Mexico	
2008	3	2	Dolly in late July, Gustav Cat 2 in late August, and Ike Cat 2 in early September	441
2009	1	0	Ida in early November	
2010	0	0	Alex crossed Mexico in June	

Source: NERC 2013 Special Reliability Assessment, May 2013, pg. 31

According to Spectra Energy, shale gas production is expected to grow significantly and conventional gas production is expected to slow.[11] On the national scale, Sargent & Lundy expects that future supply disruptions due to hurricanes to have less impact because much of the new production of natural gas supply is

[11] Source: http://www.spectraenergy.com

being obtained from inland shale deposits, which reduces the percentage of natural gas supply from hurricane prone areas.

3.1 FLORIDA GAS TRANSMISSION SYSTEM CURTAILMENT

Another documented cause of curtailment in the NERC Special Reliability Assessment report was a lightning strike in 1998 to the Perry Compressor Station in the Florida Gas Transmission System that melted all three of the main lines at that location. This event resulted in a reported 1.5 billion cubic feet per day curtailment, but electrical blackouts were avoided through demand-side management by requesting voluntary reduction in electrical consumption. Home air-conditioner consumption of electricity was reduced, and utilities switched from gas to residual fuel oil. Partial service to the natural gas lines resumed in approximately 3 days.[12]

A force majeure critical notice posted to Florida Gas Transmission website occurred on August 15, 2012, when a large sinkhole developed in Assumption Parish, Louisiana, which was in close proximity to pipeline facilities. The sinkhole caused family evacuations and created dangerous conditions that forced Florida Gas Transmission Company to shut down receipt of the natural gas production in the vicinity of the sinkhole. Curtailment of natural gas supply is not documented.

Florida Gas Transmission Company has over 70 receipt locations. Most of the system has multiple pipes laid in parallel. Pipe looping, storage facilities, and range of receipt locations help to mitigate supply disruptions and maintain system reliability.

3.2 GULFSTREAM NATURAL GAS SYSTEM CURTAILMENT

Critical notices that are posted on Gulfstream Natural Gas System contain alerts directed towards the off-takers of current line pack levels, gas processing plant disruptions, planned system maintenance, etc. that could affect deliveries to certain areas. However the actual gas disruption associated with each of the posted critical notices is not provided. Through personal correspondence with various personnel working in the industry, we understand that the critical notices posted on the website typically provide sufficient advance notice for the bulk system to compensate for regional supply disruptions, and delivery curtailments therefore do not result. S&L contacted Williams Partners L.P., part owner of the Gulfstream Pipeline,[13] and found that Gulf Stream has not

[12] Natural Gas Security Issues Related to Electric Power Systems Presentation by Argonne National Laboratory, dated November 28, 2001.

[13] Phone Call to Williams Employee, Eric Raymond on August 15, 2013.

had any curtailments in the supply of natural gas since its construction in 2002. Redundancies built into the Gulfstream Pipeline system infrastructure, such as pipe looping, interconnections with other pipelines, and storage facilities, have been used to avoid extended supply disruptions and curtailments.

3.3 EXPECTED FUTURE RATE OF CURTAILMENTS

FRCC has developed an electrical generation shortage plan (FRCC Generating Capacity Shortage Plan), which documents procedures to be used by Florida's electric utilities and governmental agencies for response to an energy emergency to increase region-wide reliability. In this plan, utilities are required to have an individual energy emergency plan that will provide additional generating capability in the event there is an energy shortage on its system and the state-wide power system.

According to the plan, when a utility in the FRCC region has inadequate generating capability, including purchased power to supply its firm load, or when fuel supplies state-wide have decreased to a level where continuous uninterruptible service is not possible, a "Generating Capacity Emergency" is declared. Proper coordination between all utilities and the government and following the outlined plan increases the reliability of the bulk power system in FRCC region during an energy emergency.

The two main pipelines in FRCC frequently post notices to their website which inform off-takers of the pipelines current "line pack." Line pack is a term used to define natural gas that occupies all pressurized sections of the pipeline network.[14] When a new supply point is added to the system, the pressure in the line is increased or increases the line pack; whereas a new delivery point decreases the pressure in the system or lowers the line pack. When line pack is low, the major pipelines post notices to the off takers indicating such line pack levels; the notice also reminds the off takers to monitor their scheduled delivery during the notice to ensure the actual delivery does not exceed the scheduled delivery. While the natural gas pipelines to the national bulk power system have been reliable in the past, future reliability may or may not reflect past observations. The FRCC region currently receives 100% of the total supply of natural gas from two pipelines. The Florida Gas Transmission Pipeline, which provides approximately 62% of Florida's total supply, has multiple redundancies built into its system. However, if similar instances experienced in the past occur near the future generation's supply off-take, curtailments could be significant. Disregarding the sinkhole incident in 2012, which has been ongoing for over a year, the longest duration of curtailment in the Southern United

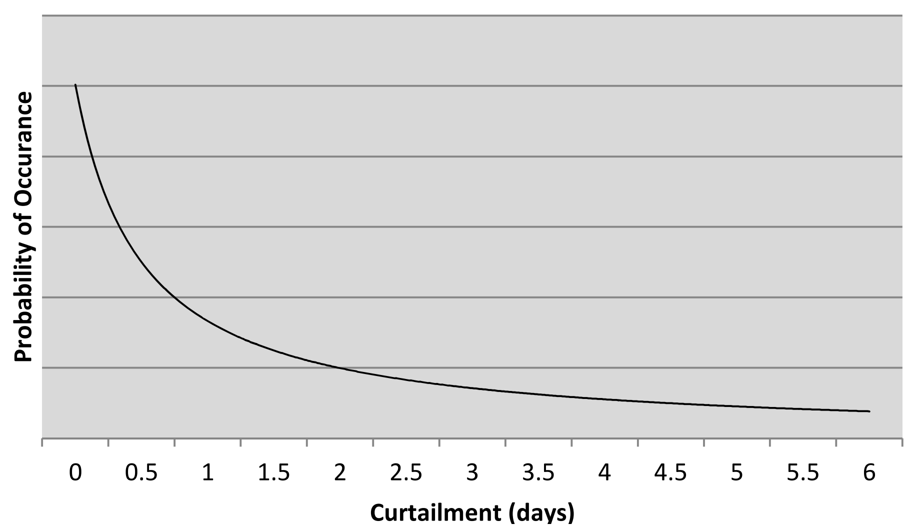
[14] Northwest Gas Association Natural Gas Term of the Week on January 1, 1970.

States occurred during the lightning strike to the Perry Compressor Station, which lasted approximately 5 days.

The historical curtailment events mentioned earlier are representative of the supply disruption on the pipeline, which may or may not have the same curtailment effect for a specific off-taker. The Perry Compressor Station lightning event previously mentioned occurred in 1998, approximately 15 years ago, suggesting that the probability of occurrence is unlikely. From the number of notices that have been sent out by both major pipelines, it is reasonable to assume the potential natural gas curtailments due to low line pack levels are more likely to occur, but the magnitude of the curtailment would be much less.

Sufficient data were not available to determine the explicit probability of curtailment for a specific plant. However, a representative probability of natural gas curtailment shown in Figure 3-1 indicates low probability of occurrence for long duration events and higher probability of occurrence for short duration events.

Figure 3-1 — Representative Relationship of Natural Gas Curtailment Probability of Occurrence and Duration



Last page of Section 3.

4. ENVIRONMENTAL CONSIDERATIONS FOR DUAL FUEL OPERATION

S&L reviewed permits issued for combined-cycle combustion turbines in Florida to identify air pollution control technologies that will likely be required for new combined-cycle combustion turbines. Recently permitted single and dual fuel-fired combined-cycle combustion turbines facility projects were permitted with similar combustion control and post-combustion control emissions technologies. Plants that use fuel oil may have a more challenging time demonstrating NO_X and SO_2 compliance, especially during start-up, and obtaining air quality permits will likely be more difficult due to NAAQS compliance challenges. The fundamental permitting considerations impacted by fuel choice are summarized in this section.

4.1 AIR PERMITTING REQUIREMENTS

The construction and operation of a new entrant electric power generating facility in the state of Florida is subject to comprehensive environmental review. Any new fossil fuel-based power generating facility that may emit air contaminants will require a permit to construct from the Florida Department of Environmental Protection (DEP). In addition to permitting requirements, all new stationary combustion sources are subject to specific air quality regulations limiting emissions from the source. Applicability of the air quality regulations is a function of the source type and size, fuel-fired, potential emissions, and location of the proposed new source.

Potential air quality standards applicable to new combined cycle combustion turbine facilities include:

- New Source Performance Standards (NSPS) (40 CFR Part 60)
- National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR Part 63)
- Florida State Stationary Source Emissions Standards (Rule 62-296, FAC)
- New Source Review (NSR) (40 CFR 52.21)

Florida standards address emissions from petroleum liquid storage tanks.

New units subject to NSR will be required to install air pollution controls and meet unit-specific emission limits established during the NSR review process. There are two types of NSR permitting requirements for new major sources: (1) Prevention of Significant Deterioration (PSD) permits, which are required for a new major source located in an attainment area; and (2) Non-attainment NSR (NNSR) permits, which are required for a new major source located in a non-attainment area. The PSD and NNSR permit requirements apply to proposed new major sources of regulated NSR/PSD air pollutants.[15] A new fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input is deemed a "major stationary source," as defined in Rule 62-210.200(194), when the facility emits, or has the potential to emit, 100 tons per year or more of any PSD pollutant, taking into consideration fugitive emissions. The major source thresholds may be reduced if the source is located in an area that does not meet the National Ambient Air Quality Standards (NAAQS) (i.e., non-attainment areas). According to Rule 62-204.340, FAC, all of the state of Florida is designated as attainment, unclassifiable, or maintenance for ozone, PM_{10}, SO_2, CO, NO_2, and lead. The U.S. EPA designates a portion of Hillsborough County as a non-attainment area for the 2008 Lead NAAQS, but new combined-cycle combustion turbines facilities will likely not emit a significant amount of lead emissions.

PSD regulations require the applicant to do the following:

- Obtain a permit before beginning construction of the new source.
- Prepare an ambient air quality impact analysis to determine whether emissions from the proposed project will cause or contribute to a violation of the applicable NAAQS or PSD increments.
- Conduct a Best Available Control Technology (BACT) review and install emission control technologies that represent BACT.
- Provide an additional impact analysis, which includes an analysis of the potential impairment to visibility, soils, and vegetation as a result of the proposed new facility, as well as the potential general commercial, residential, industrial, and other growth associated with the proposed new facility.

4.2 AMBIENT AIR QUALITY ANALYSIS

An ambient air quality impact analysis would need to be conducted for each regulated air pollutant for which the facility exceeds the significant emissions threshold to determine whether emissions from the proposed project will cause or contribute to a violation of the applicable NAAQS or PSD increments.

Potentially applicable NAAQS include the recently updated 1-hour NO_2 and SO_2 NAAQS, 100 ppb and 75 ppb, respectively. New single and dual fuel-fired combined-cycle combustion turbine facilities, regardless of fuel use, may be required to conduct ambient air quality impact analyses that include demonstrating compliance with these new 1-hour standards. Although both types of facilities may be able to demonstrate compliance with these standards, facilities firing diesel fuel oil may have a more challenging time demonstrating compliance,

[15] Regulated NSR air pollutants include carbon monoxide (CO), lead (Pb), nitrogen oxides (NOx), sulfur dioxide (SO_2), volatile organic

especially during start-up, since NO_X and SO_2 emissions from firing diesel fuel oil tend to be higher than emissions from firing natural gas. However, there are many variables that are considered during the air quality impact modeling process, and analyses must be conducted on a case-by-case basis. In the case of dual fuel capability, obtaining an air quality permit will likely be more difficult due to the expected NAAQS compliance challenges.

4.3 BACT REQUIREMENTS

BACT is defined as an emission limitation based on the maximum degree of reduction of each air pollutant emitted from a stationary air emissions source that the Florida DEP determines is achievable for such source on a case-by-case basis.

S&L conducted a review of the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database and a review of permits issued for combined-cycle combustion turbines in Florida to identify air pollution control technologies that will likely be deemed BACT for new combined-cycle combustion turbines. It should be noted that BACT requirements are continuously changing and will tend to be increasingly stringent in the future.

Recently permitted single and dual fuel-fired combined-cycle combustion turbines facility projects were permitted with similar combustion control and post-combustion control emissions technologies. For NO_X control, combined-cycle combustion turbine facilities were permitted with combustion control technologies, particularly dry low-NO_X systems to be used when firing natural gas and water injection systems when firing fuel oil (either ultra-low sulfur diesel (ULSD) or No. 2 distillate oil (DO)), and post-combustion controls, specifically selective catalytic reduction (SCR) systems, to be used when firing natural gas and fuel oil.

Table B-1 in Appendix B, provides a summary of recently issued NSR/PSD air construction permits for combined-cycle facilities in Florida, including authorized fuel use and restrictions. Between 2002 and October 2012, there were 15 facilities in Florida that received NSR/PSD Air Construction Permits for combined-cycle facilities. Twelve of the facilities that received NSR/PSD permits have combustion turbines with dual fuel capabilities. Eight of these plants are in central Florida (Pinellas, Manatee, Polk, Osceola, Orange, and Brevard counties), of which two and part of a third are gas only. Four are on the southeastern coast (St. Lucie, Martin, Palm Beach, and Dade counties), and all have ULSD backup.

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compounds (VOC), and particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}).

The data in Table B-1 show that the 15 combined-cycle faculties have comparable emissions controls technologies. Some variations between permits, relevant to this study, included authorized fuel type (e.g., natural gas only, dual-fuel using ULSD or No. 2 DO), authorized fuel oil type (e.g., ULSD 0.0015% sulfur by weight, No. 2 DO 0.05% sulfur by weight), and annual hours of operation restrictions for firing fuel oil (ranging from 500 hours to 1,000 hours per combustion turbine). Further evaluation of the facilities' Technical Evaluations would be required to evaluate each permit applicant's rationale regarding each BACT determination in order to further analyze the variations between permits.

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5. OPERATIONAL AND RELIABILITY CONSIDERATIONS

5.1 OPERATIONAL CONSIDERATIONS FOR FUEL OIL UTILIZATION

For continuous plant operations to occur on dual fuel without backup distillate fuel storage on-site, daily deliveries of about 152 trucks (unloading at approximately 9.5 minutes per truck) or 56 rail cars (unloading at approximately 26 minutes per rail-car) are required. After considering factors such as the unloading time and frequency of needed deliveries, and unreliable traffic and road/rail conditions, it is apparent that plant operation from continuous fuel shipment is impractical. The size of the backup fuel tank then becomes a tradeoff between the need to turn over inventory and the likelihood of needing the entire inventory to keep the plant running during a curtailment. A more likely scenario for distillate fuel supply in the central Florida region is either long-term on-site storage, which requires significant capital investment in land and equipment, or short-term on-site storage while connecting to an available distillate fuel supply pipeline in the area.

As a conservative measure, this study considers that the Citrus County combined-cycle facility would plan for long-term on-site storage of about three full power days of fuel supply as a contingency against gas supply interruptions, which is equivalent to about 6 million gallons. Annual testing is estimated to be about 15 full power hours per year, meaning that the average turnover period of this fuel just from testing would be about five years. Normally, the life of diesel fuel is considerably shorter than five years; for example, NFPA 110 refers to the storage life of diesel fuel as 18 months to two years.

Maintaining fuel quality at such a low rate of turnover would require a fuel management program to deal with degradation of the fuel over time from such causes as repolymerization, organic growth (bacteria, algae, and fungi), and oxidation. Additives can be used to control such degradation. Control of moisture in storage tanks can reduce degradation problems. A testing program should be instituted to monitor fuel quality and stability. Depending on experience with fuel stability and degradation, it might be necessary to turn the fuel over at a higher rate than just needed for testing. The economic analysis in Section 5 of this report does not include oil consumption beyond the assumed 15 hour per year engine testing program, nor are costs of oil testing and stabilization included in that analysis.

5.2 BACKUP FUEL CAPABILITY OF EXISTING COMBINED-CYCLE PLANTS IN FRCC

To assess the prevalence of backup fuel capability in combined cycle plants in FRCC, we extracted from the Ventyx Velocity database a list of all combined-cycle plants in FRCC having generating capacity 200 MW or more that are operating or planned. We checked the primary and backup fuel capabilities of those units against tables in "FRCC 2013 Regional Load & Resource Plan," published July 2013. Forty combined-cycle plants were identified, of which 23 (58%) have natural gas as primary fuel and diesel or distillate fuel oil as backup fuel, and 17 (43%) have natural gas as primary fuel but no backup fuel is identified in the FRCC document. Considered on a megawatt basis, about half the capacity has backup fuel capability and half does not.

Most of Duke Energy's plants (shown as Progress Energy Florida in the figures) have backup fuel capability. Each individual plant's incremental impact on system reliability is likely small because the backup capability of the existing fleet as a whole provides significant reliability for the electrical system. The utilities in Florida also have the ability to use alternate backup fuels at numerous dual-fuel simple-cycle CT and steam generating stations to support overall system reliability if gas availability is curtailed for some reason.

Plants in the FRCC region that have backup fuel capability are listed in the following table.

Table 5-1 — Combined-Cycle Units in FRCC Exceeding 200 MW with Backup Fuel Capability

plant	owner	MW	startup	primary fuel	backup fuel
Treasure Coast Energy Center	Florida Municipal Power Agency	411	5/31/2008	Gas	DFO
Cape Canaveral	Florida Power & Light Co	1,219	4/24/2013	Gas	DFO
Lauderdale	Florida Power & Light Co	521	5/1/1993	Gas	DFO
Lauderdale	Florida Power & Light Co	521	6/1/1993	Gas	DFO
Martin (FL)	Florida Power & Light Co	612	2/1/1994	Gas	DFO
Martin (FL)	Florida Power & Light Co	612	4/1/1994	Gas	DFO
Port Everglades	Florida Power & Light Co	1,277	6/30/2016	Gas	DFO
Putnam (FL)	Florida Power & Light Co	290	8/1/1977	Gas	DFO
Putnam (FL)	Florida Power & Light Co	290	4/1/1978	Gas	DFO
Riviera	Florida Power & Light Co	1,219	6/1/2014	Gas	DFO
West County Energy Center	Florida Power & Light Co	1,421	7/27/2011	Gas	DFO
Hardee Power Station	Hardee Power Partners Ltd	287	7/1/1992	Gas	DFO
Brandy Branch	JEA	598	3/31/2005	Gas	DFO
Hines Energy Complex	Progress Energy Florida	547	4/1/1999	Gas	DFO
Hines Energy Complex	Progress Energy Florida	516	12/9/2003	Gas	DFO
Hines Energy Complex	Progress Energy Florida	590	11/7/2005	Gas	DFO
Hines Energy Complex	Progress Energy Florida	610	12/31/2007	Gas	DFO
P L Bartow	Progress Energy Florida	1,253	6/26/2009	Gas	DFO
Richard J Midulla Generating Stn	Seminole Electric Coop Inc	587	1/1/2002	Gas	DFO
Stanton Energy Center	Southern Co Florida LLC	447	10/1/2003	Gas	DFO
Stanton Energy Center	Southern Power Co	216	12/31/2009	Gas	DFO
Arvah B Hopkins	Tallahassee FL (City of)	447	7/1/2008	Gas	DFO
S O Purdom	Tallahassee FL (City of)	247	7/1/2000	Gas	DFO
total with backup fuel (23 plants)		14,739			

Plants in the FRCC region that do not have backup fuel capability are as follows:

Table 5-2 — Combined-Cycle Units in FRCC Exceeding 200 MW without Backup Fuel Capability

plant	owner	MW	startup	primary fuel	backup fuel
Osprey Energy Center	Calpine Constr. Finance Co LP	644	5/27/2004	Gas	None
Cane Island	Florida Municipal Power Agency	324	7/12/2011	Gas	None
Fort Myers	Florida Power & Light Co	1,722	5/30/2002	Gas	None
Manatee (FPL)	Florida Power & Light Co	1,225	6/30/2005	Gas	None
Martin (FL)	Florida Power & Light Co	1,225	6/30/2005	Gas	None
Sanford (FL)	Florida Power & Light Co	1,360	6/14/2002	Gas	None
Sanford (FL)	Florida Power & Light Co	1,360	4/1/2003	Gas	None
Turkey Point	Florida Power & Light Co	1,224	5/1/2007	Gas	None
West County Energy Center	Florida Power & Light Co	1,421	10/27/2009	Gas	None
West County Energy Center	Florida Power & Light Co	1,421	11/3/2009	Gas	None
Lansing Smith	Gulf Power Co	620	4/22/2002	Gas	None
C D McIntosh Jr	Lakeland Dept of Electric Water Utils	369	4/4/2002	Gas	None
Tiger Bay	Progress Energy Florida	278	8/1/1997	Gas	None
Santa Rosa Energy Center	Santa Rosa Energy Center LLC	275	6/6/2003	Gas	None
Bayside Power Station	Tampa Electric Co	809	4/1/2003	Gas	None
Bayside Power Station	Tampa Electric Co	1,205	1/15/2004	Gas	None
Polk Station	Tampa Electric Co	580	1/1/2017	Gas	None
total without backup fuel (17 plants)		16,060			

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6. COST OF PROVIDING BACKUP FUEL CAPABILITY

Sargent & Lundy developed estimates of the costs of providing backup fuel capability. Costs are measured by the capital investment costs required for dual-fuel operation, fuel oil testing at commissioning, fuel oil inventory costs, annual fuel oil testing, and fuel oil consumption during curtailments. O&M costs during fuel oil operation are not estimated because the incremental cost above natural gas operation is negligible. The avoided costs of natural gas supply curtailments over the operating life of the plant are based on the equivalent cost of wholesale power purchases during the curtailments. Avoided costs of natural gas consumption during curtailments are not included since they are the same whether or not backup fuel capability is provided. The derivation of the cost components are described in the following subsections.

6.1 CAPITAL INVESTMENT FOR DUAL FUEL OPERATION

Dual-fuel operation requires additional piping, storage tanks, and related facilities. Fuel oil tanks were sized on the basis of three days of full-load backup ULSD inventory, which is equivalent to approximately 6,000,000 gallons. Sargent & Lundy estimated the total cost of these facilities to be $28,310,000 (in 2013 $) which includes $24,052,000 in direct costs, $1,684,000 in owner’s costs, and $2,574,000 in financing costs during construction. The detailed cost estimate is provided in Table 6-1 below. Capital investment costs are assumed to escalate by 2.5% per year between 2013 and the 2017 commercial operation date (COD). Financing costs during construction are not included in this estimate.

Table 6-1 — Conceptual Cost Estimate for Fuel Oil Operation

Acct No.	Item Description	Total Projected Cost	
10.00	**General Site Work**	**$**	**193,857**
10.10	Civil Site Work	$	147,163
10.90	Construction Indirects	$	46,694
11.00	**Underground**	**$**	**354,639**
11.10	Civil Undergroud Works	$	267,142
11.90	Construction Indirects	$	87,497
21.00	**Combustion Turbine**	**$**	**9,836,205**
21.20	Concrete Works	$	9,920
21.50	Electrical	$	78,360
21.60	Mechanical - Combustion Turbines	$	8,856,793
21.70	Piping	$	785,358
21.90	Construction Indirects	$	105,774
55.00	**Water Treatment**	**$**	**2,072,599**
55.20	Concrete Works	$	436,263
55.60	Mechanical	$	180,514
55.90	Construction Indirects	$	135,822
55.99	Subcontract - Demineralized Storage Tank	$	1,320,000
70.00	**Electrical Power Distribution**	**$**	**145,726**
70.50	Electrical	$	121,793
70.90	Construction Indirects	$	23,933
75.00	**Distributed Control System**	**$**	**380,462**
75.55	Instrumentation	$	347,981
75.90	Construction Indirects	$	32,481
80.00	**Balance of Plant Works**	**$**	**7,931,133**
80.20	Concrete Works	$	2,725,397
80.45	Painting & Coating	$	76,419
80.60	Mechanical - Fuel Oil Forwarding Pumps	$	262,862
80.70	BOP Piping	$	438,107
80.80	Insulation	$	85,337
80.90	Construction Indirects	$	1,050,811
80.99	Subcontract - Fuel Oil Storage Tank	$	3,292,200
OP.00	**Subtotal - Project Costs**	**$**	**20,914,621**
	Project Contingency at 15%	$	3,137,193
	Subtotal - Overall Project Costs	**$**	**24,051,814**
	Owner's Costs	$	1,684,000
	Financing Costs during Construction		Not Included
PI.00	**Total - Overall Project Costs**	**$**	**25,735,814**

6.2 FUEL OIL TESTING AT COMMISSIONING

Approximately 30 hours of the plant commissioning period must include fuel oil testing. The cost of testing is measured as an incremental cost of fuel at full load over this period compared to gas firing. Based on the forecasted cost of $23.33/mmBtu for ULSD and $5.72/mmBtu for natural gas at the 2017 COD, along with the previously indicated values for plant output and heat rate, the fuel oil testing cost at commissioning is $6,060,000 (in 2017 $).

6.3 FUEL OIL INVENTORY COSTS

Maintaining on-site inventory of fuel oil results in the incurrence of substantial inventory carrying charges. For example, Duke would experience inventory carrying charges of nearly $3 million per year for an on-site inventory of 6 million gallons of ULSD at the Citrus County site.

On the basis of a three-day full-load inventory of ULSD, a heating value of 138,876 Btu/gallon, a fuel price of $23.33/mmBtu at the COD, and the previously indicated values for plant output and heat rate, the fuel oil inventory cost is $19,265,000. The economic analysis provides a credit for the fuel oil inventory at the end of the evaluation period.

6.4 ANNUAL FUEL OIL TESTING

Over the plant operating life, approximately 15 hours per year must include fuel oil testing. The cost of testing is measured as an incremental cost of fuel at full load over this period compared to gas firing. Based on the forecasted cost of $24.68/mmBtu for ULSD and $5.96/mmBtu for natural gas during the first year of operation, along with the previously indicated values for plant output and heat rate, the fuel oil testing cost during the first year of operation is $3,134,000 per year.

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Appendix A

Permitting Summary for Combined Cycle Facilities in Florida

Sargent & Lundy LLC Consulting

Table A-1 — Summary of Recently Issued NSR/PSD Air Construction Permits for Combined-Cycle Facilities in Florida State

Facility	Cane Island Power Park	FPL Cape Canaveral Energy Center	FPL Manatee Power Plant	FPL Martin Power Plant	FPL Turkey Point Fossil Plant	FPL West County Energy Center	Hines Energy Complex	Hines Energy Complex	Hines Energy Complex	H.L. Culbreath Bayside Power Station	H.L. Culbreath Bayside Power Station	Stanton Energy Center	TEC Polk Power Station	Treasure Coast Energy Center	PEF Bartow Power Plant
Project	Unit 4	Unit 3	Unit 3	Unit 8	Unit 5	Unit 3	PB 2	PB 3	PB 4	Units 1 and 2	Units 3 and 4	Unit B	Polk 2	Unit 1	Repowering
Location	Osceola County	Brevard County	Manatee County	Martin County	Miami-Dade County	Loxahatchee	Polk County	Polk County	Polk County	Brevard County	Brevard County	Orange County	Polk County	St. Lucie County	Pinellas County
Permit No.	PSD-FL-400	0090006-005-AC	PSD-FL-328	PSD-FL-327E	PSD-FL-338	PSD-FL-396	PSD-FL-296A	PSD-FL-330	PSD-FL-342	PSD-FL-301C	PSD-FL-301C	PSD-FL-373A	PSD-FL-421	PSD-FL-353	PSD-FL-381
Permit Application Date	3/27/2008	12/29/2008	2002	7/2011	1/4/2003	11/20/2007	2003	2003	2003	2004	2004	2/2008	10/2012	4/14/2005	7/28/2006
Air Construction Permit Date (Final/Draft)	9/5/2008 (Final)	7/23/2009 (Final)		2012 (Draft)	2/8/2005 (Final)	7/30/2008 (Final)	(Final)	(Final)	(Final)	(Final)	(Final)	5/4/2008 (Final)	2013 (Draft)	5/19/2006 (Final)	(Final)
Commercial Operation Date	2/7/2011	12/2010	5/23/2005	2001 & 2004	12/2006	12/2010	8/2003	8/2005	9/2007	2003	2009	11/27/2009	8/4/1996	2/12/2008	12/2008
BACT Analysis	CO NOx PM/PM10 SAM SO2	N/A	CO NOx PM/PM10 SAM VOC SO2	N/A	CO NOx PM/PM10 SAM SO2 VOC	CO NOx PM/PM10 SAM SO2 VOC	CO NOx PM/PM10 SAM VOC SO2	CO NOx PM/PM10 SAM VOC SO2	CO NOx PM/PM10 SAM SO2	CO PM/PM10 VOC	CO PM/PM10 VOC	CO NOx PM/PM10/PM2.5 SAM SO2	CO NOx PM/PM10/PM2.5 SAM VOC SO2	CO NOx PM/PM10 SAM SO2	CO VOC
Facility Characteristics:															
Project MW	300 MW	1,295 MW	1,150 MW	1,150 MW	1,150 MW	1,250 MW	530 MW	530 MW	530 MW	1,836 MW	1,009 MW	300 MW	1,160 MW	300 MW	1,280 MW
CTG(s) Dual Fuel Capabilities	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Fuel Type(s):	NG	NG / ULSD (restricted alternate)	NG	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG	NG / No. 2 DO Unit 3 Only (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / DO (restricted alternate)
CTG(s)	1 x 150 MW w/ DB/HRSG	3 x 265 MW w/ DB/HRSG	4 x 170 MW w/ DB/HRSG	4 x 170 MW w/ DB/HRSG	4 x 170 MW w/ DB/HRSG	3 x 250 MW w/ DB/HRSG	2 x 170 MW w/ HRSG	2 x 170 MW w/ HRSG	2 x 170 MW w/ HRSG	7 x 169 MW w/ HRSG	4 x 169 MW w/ HRSG	1 x 150 MW w/ DB/HRSG	3 x 165 MW w/ DB/HRSG	1 x 170 MW w/ DB/HRSG	4 x 215 MW w/ DB/HRSG
STG(s)	1 x 150 MW	1 x 500 MW	1 x 470 MW	1 x 500 MW	1 x 470 MW	1 x 500 MW	1 x 190 MW	1 x 190 MW	1 x 190 MW	6 x 125 MW (shared with Units 3 and 4)	6 x 125 MW (shared with Units 1 and 2)	1 x 150 MW	1 x 500 MW	1 x 130 MW	1 x 420 MW
Emissions Controls	Combustion controls for NOx; SCR for NG/FO	DLN for NG; WI for FO; SCR	DLN; SCR	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN; SCR	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO	Combustion controls for NG; WI for FO; SCR for NG/FO	DLN for NG; WI for FO; SCR for NG/FO
FO-Fired SU/SD Gen(s)	1 x 750 kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1 x 1,525 kW	N/A
FO-Fired Emer. Gen(s)	N/A	2 x 2,250 kW	N/A	N/A	N/A	2 x 2,250 kW	N/A	N/A	N/A	N/A	N/A	N/A	2 x 500 kW	N/A	N/A
FO-Fired Emer. Fire Pump Engine(s)	1 x 300 hp	1 x 300-hp	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1 x 300 hp	1 x 300 hp

Facility	Cane Island Power Park	FPL Cape Canaveral Energy Center	FPL Manatee Power Plant	FPL Martin Power Plant	FPL Turkey Point Fossil Plant	FPL West County Energy Center	Hines Energy Complex	Hines Energy Complex	Hines Energy Complex	H.L. Culbreath Bayside Power Station	H.L. Culbreath Bayside Power Station	Stanton Energy Center	TEC Polk Power Station	Treasure Coast Energy Center	PEF Bartow Power Plant
Air Construction Permit															
Fuel Type(s):															
CTG(s)	NG only	NG / ULSD (restricted alternate)	NG only	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG / No. 2 DO (restricted alternate)	NG only	NG / No. 2 DO Unit 3 Only (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / ULSD (restricted alternate)	NG / DO (restricted alternate)
HRSG w/ DB	NG only	NG only	NG only	TBD	NG only	NG only	N/A	N/A	N/A	N/A	N/A	NG only	NG only	NG only	NG only
NG Restrictions:															
CTG(s)															
Sulfur Content	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF
Annual HOP Limit	8,760	8,760	8,760	TBD	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
HRSG w/ DB															
Sulfur Content	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	TBD	2.0 gr/100 SCF	2.0 gr/100 SCF	N/A	N/A	N/A	N/A	N/A	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF	2.0 gr/100 SCF
Annual HOP Limit	8,760	8,760	8,760	TBD	8,760	8,760	N/A	N/A	N/A	N/A	N/A	8,760	Ave. 4,000 hrs per DB over the 4 CTGs	8,760	2,434 hrs per DB (9,736 hrs over the 4 DB)
FO Restrictions:															
Sulfur Content	N/A	0.0015% by wt	N/A	0.0015% by wt	0.0015% by wt	0.0015% by wt	0.05% by wt	0.05% by wt	0.05% by wt	N/A	0.05% by wt (Unit 3 only)	0.0015% by wt	0.0015% by wt	0.0015% by wt	0.05% by wt
Annual HOP Limit (Daily HOP Limit)	N/A	3,000 hrs aggregate over the 3 CTGs	N/A	TBD	500 hrs	500 hrs per CTG	19,703,000 gallons (~720 hrs)	19,703,000 gallons (~720 hrs)	30,700,000 gallons (~1,000 hrs)	N/A	If NG not available; If no FO used >875 full load hrs (Unit 3 only)	1,000 hrs	750 ave. hrs per CTG (48 hrs per day)	500 hrs	1,000 hrs per CTG (5,000 hrs over the 5 CTGs)
FO-Fired Auxiliary Equipment Restrictions:															
FO-Fired SU/SD Gen(s)															
Sulfur Content	0.0015% by wt	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0015% by wt	N/A
Annual HOP Limit	As needed w/ 200 hrs non-emergency maintenance testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	200 hrs	N/A
FO-Fired Emer. Gen(s)															
Sulfur Content	N/A	0.0015% by wt	N/A	N/A	N/A	0.0015% by wt	N/A	N/A	N/A	N/A	N/A	N/A	15 ppm	N/A	N/A
Annual HOP Limit	N/A	160 hours	N/A	N/A	N/A	160 hrs	N/A	N/A	N/A	N/A	N/A	N/A	100 hrs	N/A	N/A

Facility	Cane Island Power Park	FPL Cape Canaveral Energy Center	FPL Manatee Power Plant	FPL Martin Power Plant	FPL Turkey Point Fossil Plant	FPL West County Energy Center	Hines Energy Complex	Hines Energy Complex	Hines Energy Complex	H.L. Culbreath Bayside Power Station	H.L. Culbreath Bayside Power Station	Stanton Energy Center	TEC Polk Power Station	Treasure Coast Energy Center	PEF Bartow Power Plant
FO-Fired Emer. Fire Pump Engine(s)															
Sulfur Content	0.0015% by wt	0.0015% by wt	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0015% by wt	0.05% by wt
Annual HOP Limit	Emergency conditions; 80 hrs non-emergency maintenance testing	Emergency conditions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	200 hrs	Emergency conditions; 40 hrs non-emergency maintenance testing

Note: Acronyms and abbreviations used in the table are as follows: CTG – Combustion Turbine Generator ; DB – Duct Burners; DLN – Dry Low NOx; DO – Distillate Oil; Emer. Gen – Emergency Generator; FL – Florida; FO – Fuel Oil; FPL – Florida Power and Light Company; gr/100 SCF - grains per 100 standard cubic feet; HOP – Hours of Operation; hp – Horsepower; hrs – Hours; HRSG – Heat Recovery Steam Generator; kW – Kilowatt; MW – Megawatts; N/A – Not Applicable; NG – Natural Gas; PEF - Progress Energy Florida; PSD – Prevention of Significant Deterioration; SCR – Selective Catalytic Reduction; STG – Steam Turbine Generator; SU/SD – Start-up/Shut-down; TBD – To Be Determined; TEC – Tampa Electric Company; ULSD – Ultra-low Sulfur Diesel; WI – Water Injection; wt – Weight

Last page of Appendix B.

Citrus County Combined Cycle Power Plant Estimate

Estimate Category	**$ Million (nominal)**
Major Equipment and Engineering, procurement and Construction (EpC)	$1,121
Owners Costs including Transmission and Contingency	$229
Subtotal Project Estimate	**$1,350**
AFUDC	$164
Total Project Cost	**$1,514**

Citrus County Combined Cycle Power Plant Projected Schedule/Key Milestones

Key Project Milestone	**Date**
File Need Petition	May 2014
File SCA	August 2014
Award/Release EPC Contract	October 2014
Need Order issued by FPSC	October 2014
Award/Release Major Equipment Contracts	November 2014
SCA Approval	October 2015
EPC Begin Construction	January 2016
Receive Major Equipment	November 2016
Mechanical Completion – First Fire Block 1	November 2017
COD Block 1	May 2018
Mechanical Completion – First Fire Block 2	May 2018
COD Block 2	December 2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 6
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-5

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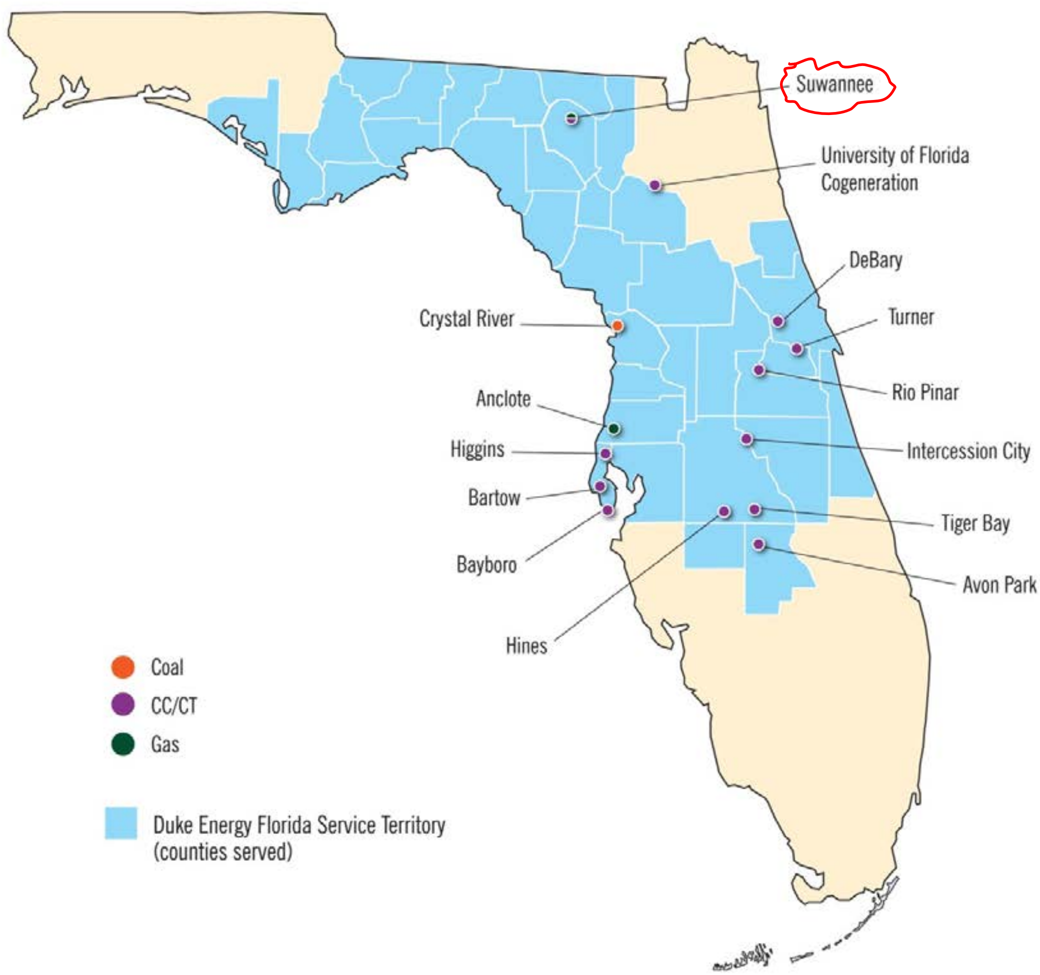
Duke Energy Florida
Exhibit No. ____ (MEL-1)
Page 1 of 1

Map Showing Location of Suwannee Power Plant Site



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 7
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-1

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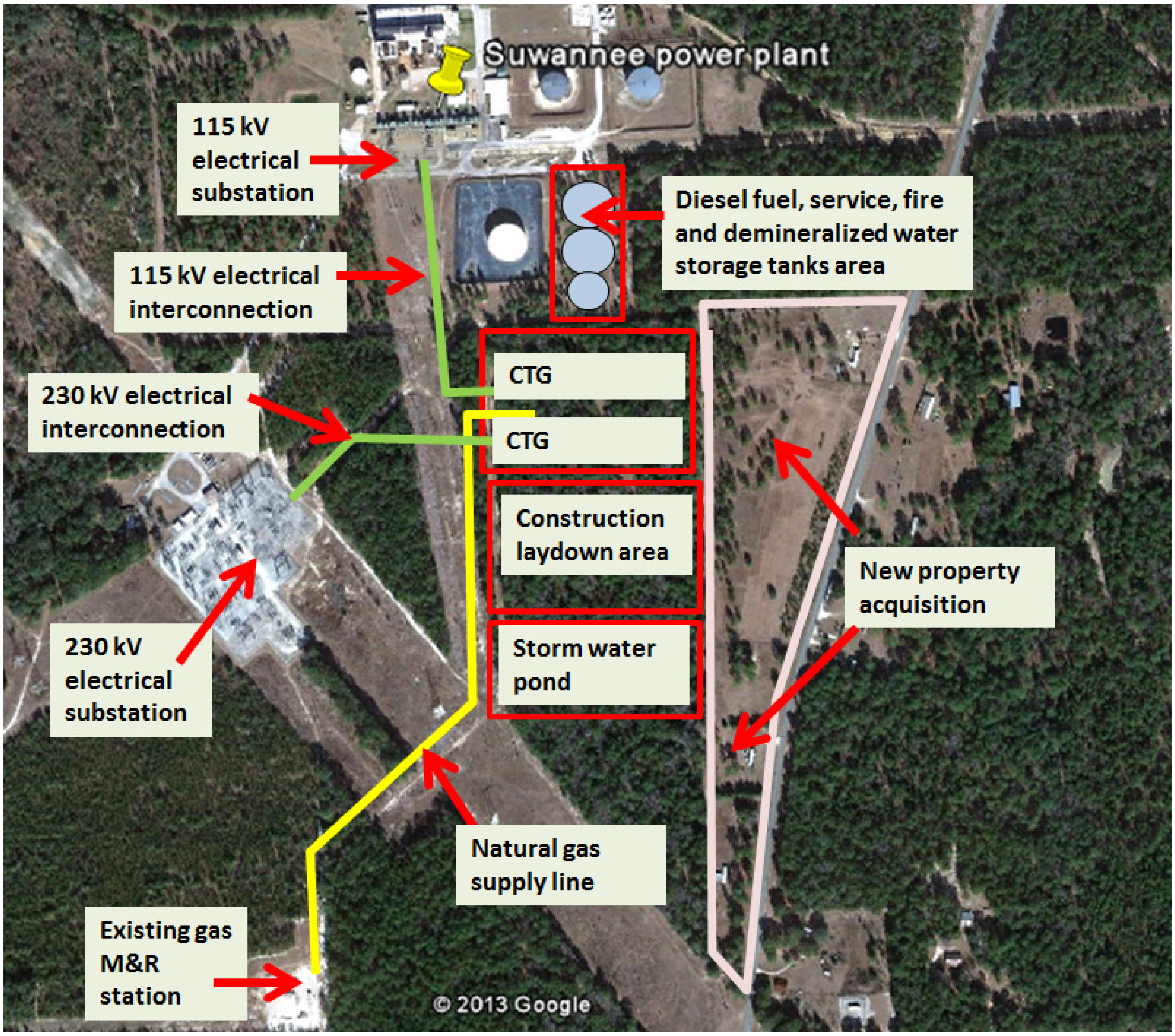
Duke Energy Florida
Exhibit No. _____ (MEL-2)
Page 1 of 1

Layout of Suwannee Simple Cycle Project at Suwannee Power Plant Site



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 8
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-2

Suwannee Simple Cycle
Major Cost Items

Estimate Category	**$ Million**
Major Equipment and Engineering, procurement and Construction (EpC)	$136
Owners Costs including Transmission and Contingency	$44
Subtotal Project Estimate	**$180**
AFUDC	$17
Total Project Cost	**$197**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-3

Projected Schedule for Completion of Suwannee Simply Cycle Project

Key Project Milestone	**Date**
Submit Air Permit Application	April 2014
Award/Release CTG Contract	May 2014
Award/Release EPC Contract	July 2014
FPSC Need Filing	May 2014
Receive Air Permit	October 2014
Expected Final FPSC Order	October 2014
EPC Begin Construction	November 2014
CTG Site Delivery	June 2015
Mechanical Completion	January 2016
First Fire	February 2016
Commercial Operation	June 2016

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Exhibit No. ______ (MEL-5)
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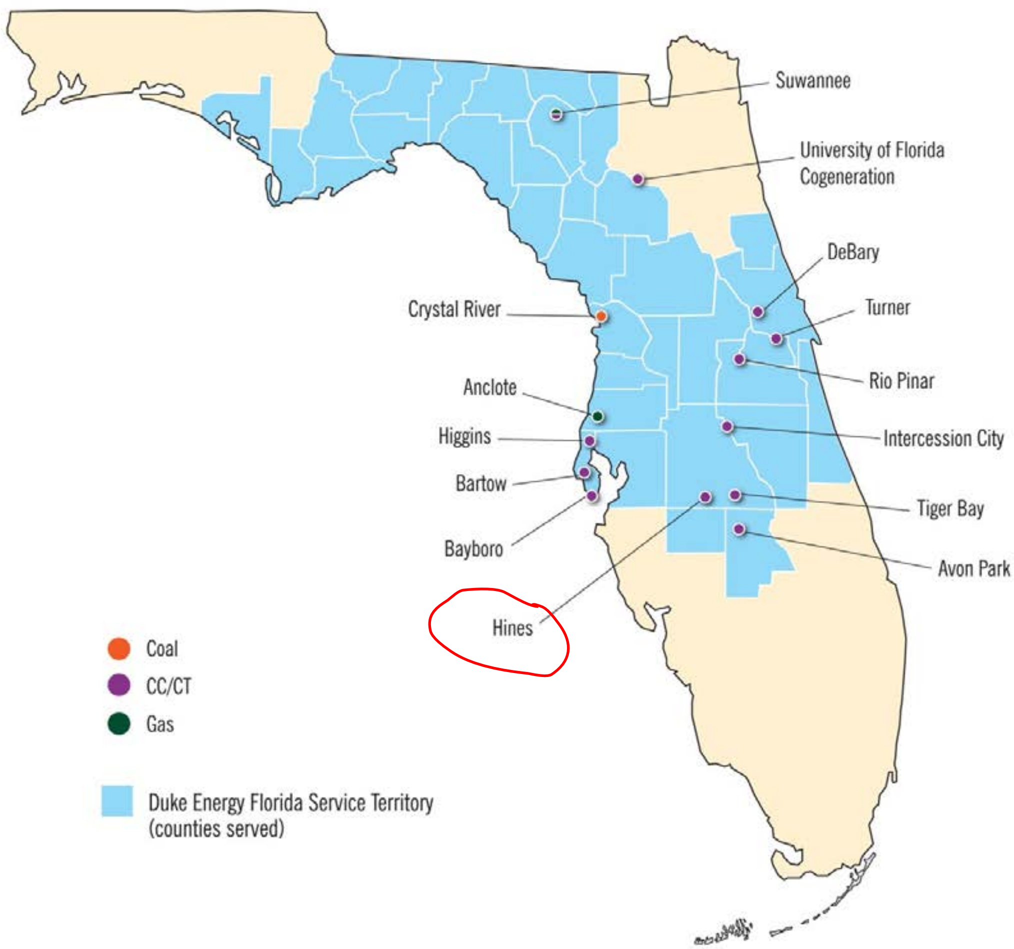
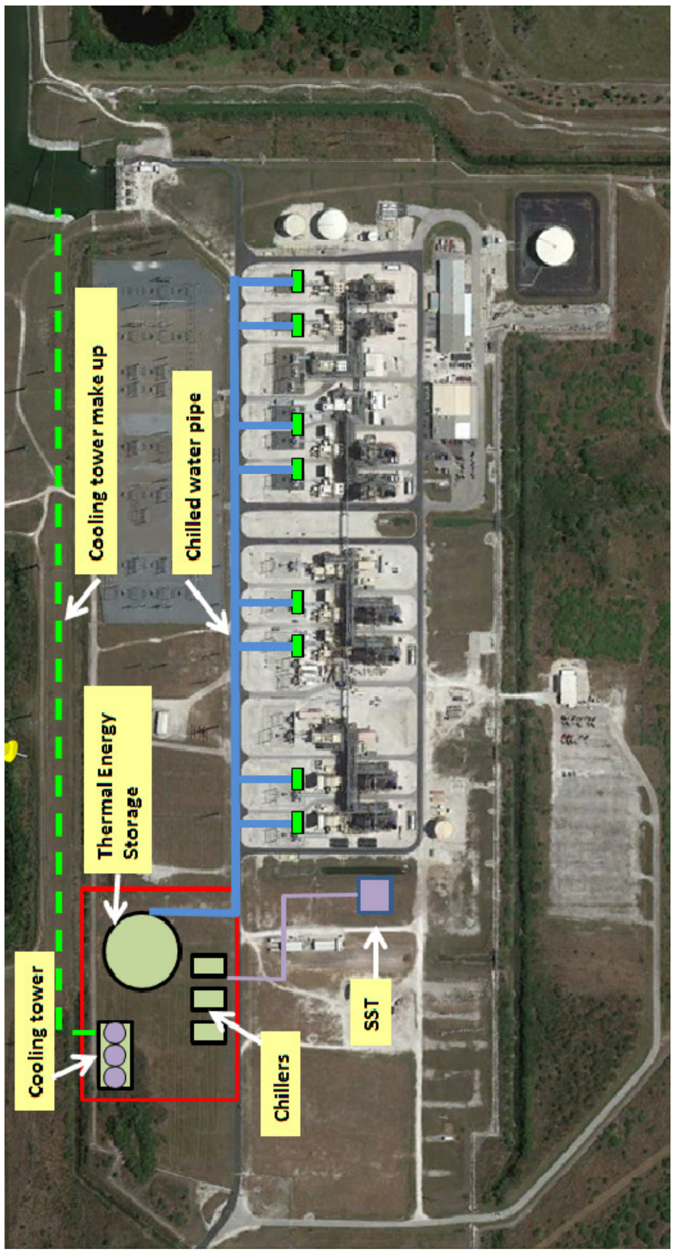
Hines Chillers Map Location of Hines Chiller Uprate Project



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 11
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-5

Layout Hines Chiller Power Uprate Project



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 12
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Mark E. Landseidel MEL-6

Hines Chillers Power Uprate
Cost Items

Estimate Category	**$ Million**
Major Equipment and Engineering, procurement and Construction (EpC)	$120
Owners Costs including Contingency	$30
Subtotal Project Estimate	**$150**
AFUDC	$10
Total Project Cost	**$160**

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Duke Energy Florida
Exhibit No. ____ (MEL-8)
Page 1 of 1

Projected Schedule for Completion Hines Chillers Power Uprate Project

Key Project Milestone	Date
FPSC Need Filing	May 2014
Bid Chiller Equipment/EPC	July 2014
Expected Final FPSC Order	October 2014
Receive Air Permit	December 2014
Award Chiller Equipment/EPC	January 2015
EPC Begin Construction	June 2015
Commercial Operation (all 4 blocks)	By June 2017

2018 Citrus Combined Cycle – Permits List

Permit Required	**Issued By**
PPSA Site Certification (includes state, local permitting and authorizations) • 401 Water Quality Certification • Domestic Wastewater • Industrial Wastewater (non-NPDES) • Water Use Permit • Environmental Resource Permit (ERP) • Spill Prevention Control Measures Permit • Local Construction Permits/Requirements • State Wildlife Permits	Florida Department of Environmental Protection (FDEP)
Water Discharge to Surface Waters (NPDES) Permit	FDEP as delegated by the Environmental Protection Agency
Prevention of Significant Deterioration (PSD)Air Construction Permit	FDEP as delegated by the Environmental Protection Agency
Air: Title V Operating Permit	FDEP as delegated by the Environmental Protection Agency
Clean Water Act Section 404 Permit	US Army Corps of Engineers
Environmental Resource Permit (ERP)[1]	FDEP
Clean Water Act Section 404 Permit[1]	US Army Corps of Engineers
Federal Aviation Administration Permit	FAA
Comprehensive Plan Amendment	Citrus County
Zoning Atlas Change	Citrus County

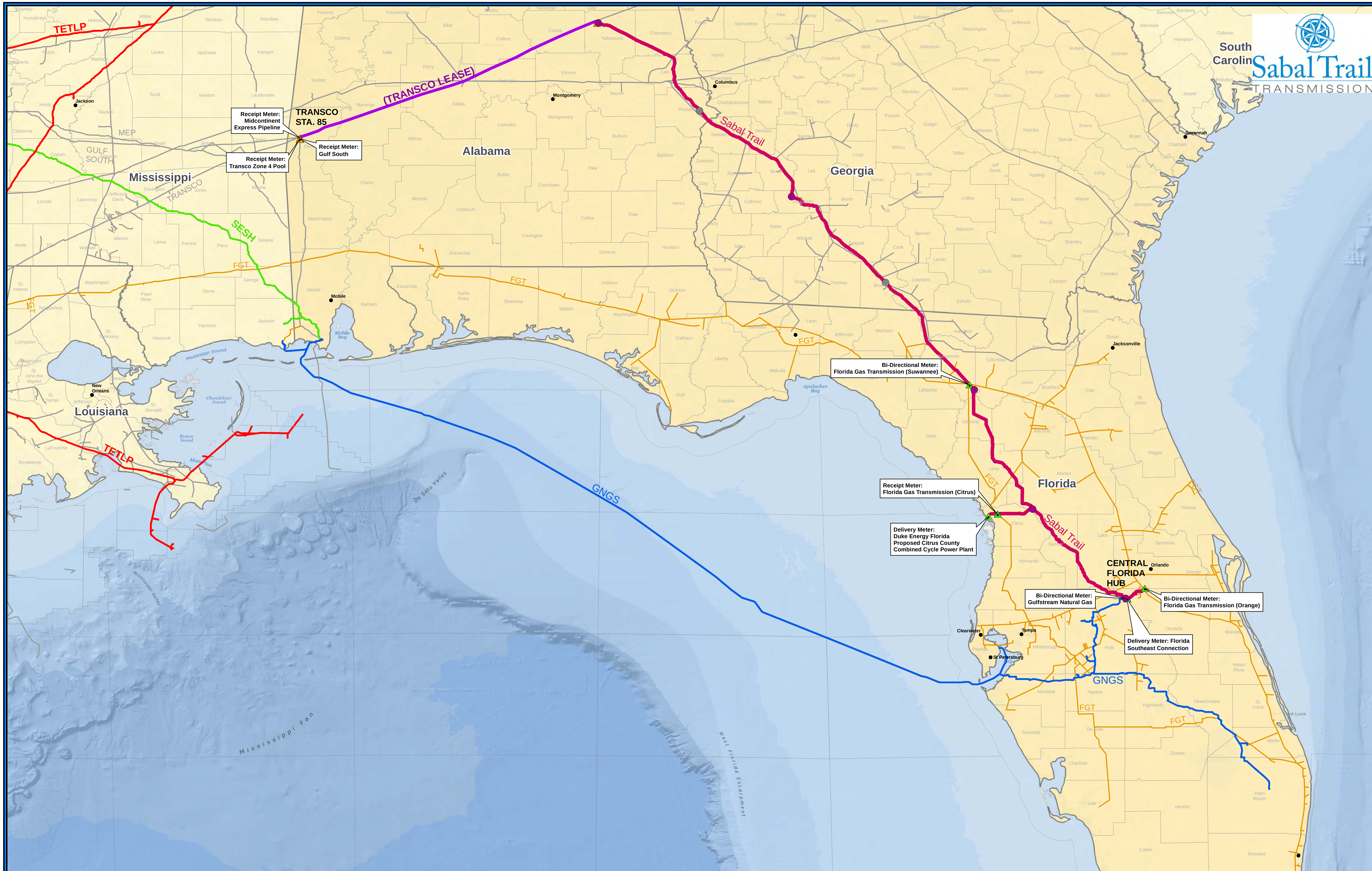
Footnote
1- A separate ERP and Clean Water Act 404 permit modification will be needed to separate the permits from the existing landowner to Duke Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 16
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Amy Dierolf AD-2 (140110-EI)

Key Dates in the Anticipated Schedule for Review of Site Certification Application for Duke Energy Florida's Citrus Combined-Cycle Plant[1]	
Date	**Requirement/Deadline**
Aug. 1, 2014	DEF files the SCA
Sept. 2, 2014	AGENCIES submit recommendations regarding the completeness of the SCA to DEP.
Sept. 10, 2104	DEP issues 1st Completeness Determination on the SCA.
Oct. 10, 2014	DEF files additional information in response to DEP's 1st determination
Oct. 21, 2014	CITRUS COUNTY issues its determination of land use/zoning consistency for power plant site and associated facilities that are not exempt from the definition of "development."
October 2014	PSC to issue Agency Report/Need Determination.
Nov. 3, 2014	DEP issues 2nd Completeness Determination on the plant and non-transmission portion of the SCA (if necessary)
Dec. 3, 2014	DEF files additional information in response to DEP's 2nd determination (if necessary)
Dec. 26, 2014	DEP issues 3rd Completeness Determination on the SCA (assumes SCA complete).
Jan. 5, 2015	ALJ conducts hearing on the challenge to the determination of land use consistency, if one (schedule assumes a 2-day hearing).
February 5, 2015	ALJ issues Recommended Order from hearing on land use consistency.
March 31, 2015	SITING BOARD hearing on land use consistency.
April 6, 2015	AGENCIES issue reports as to matters within their jurisdiction.
May 5, 2015	DEP files Project Analysis
June 17, 2015 **June 23, 2015**	ALJ conducts hearing on Site Certification (schedule assumes a 5-workday hearing)
August 14, 2015	ALJ issues Recommended Order on Site Certification
October 13, 2015	SITING BOARD hearing on Site Certification.
October 19-23, 2015	Governor signs the Siting Board Order

[1] This is an anticipated schedule of key dates only. Not all Power Plant Siting Act (PPSA) deadlines are reflected on this schedule. The DEP is responsible for preparing and filing the schedule for review of the Project, and the assigned administrative law judge issues the order establishing the schedule. The dates shown here are, therefore, estimated and subject to change.

Exhibit JP-1 in Docket 140110-EI



Y:\Personal\Maps\Sabal Trail\Sabal Trail Transmission LLC-Duke Energy - 8-14-13.mxd

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Duke Energy Florida
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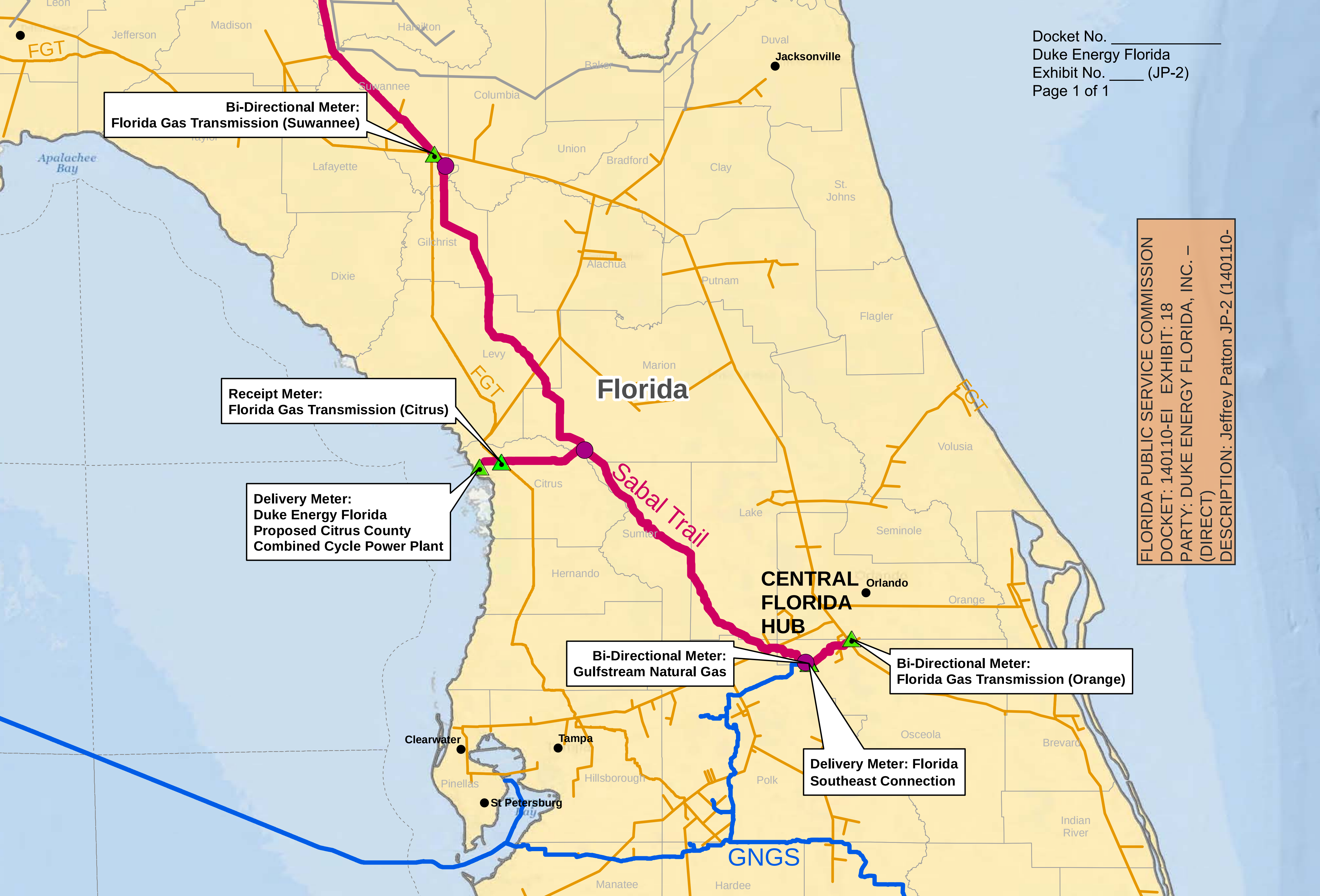
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 18
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Jeffrey Patton JP-2 (140110-



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 19
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Jeffrey Patton JP-3 (140110-

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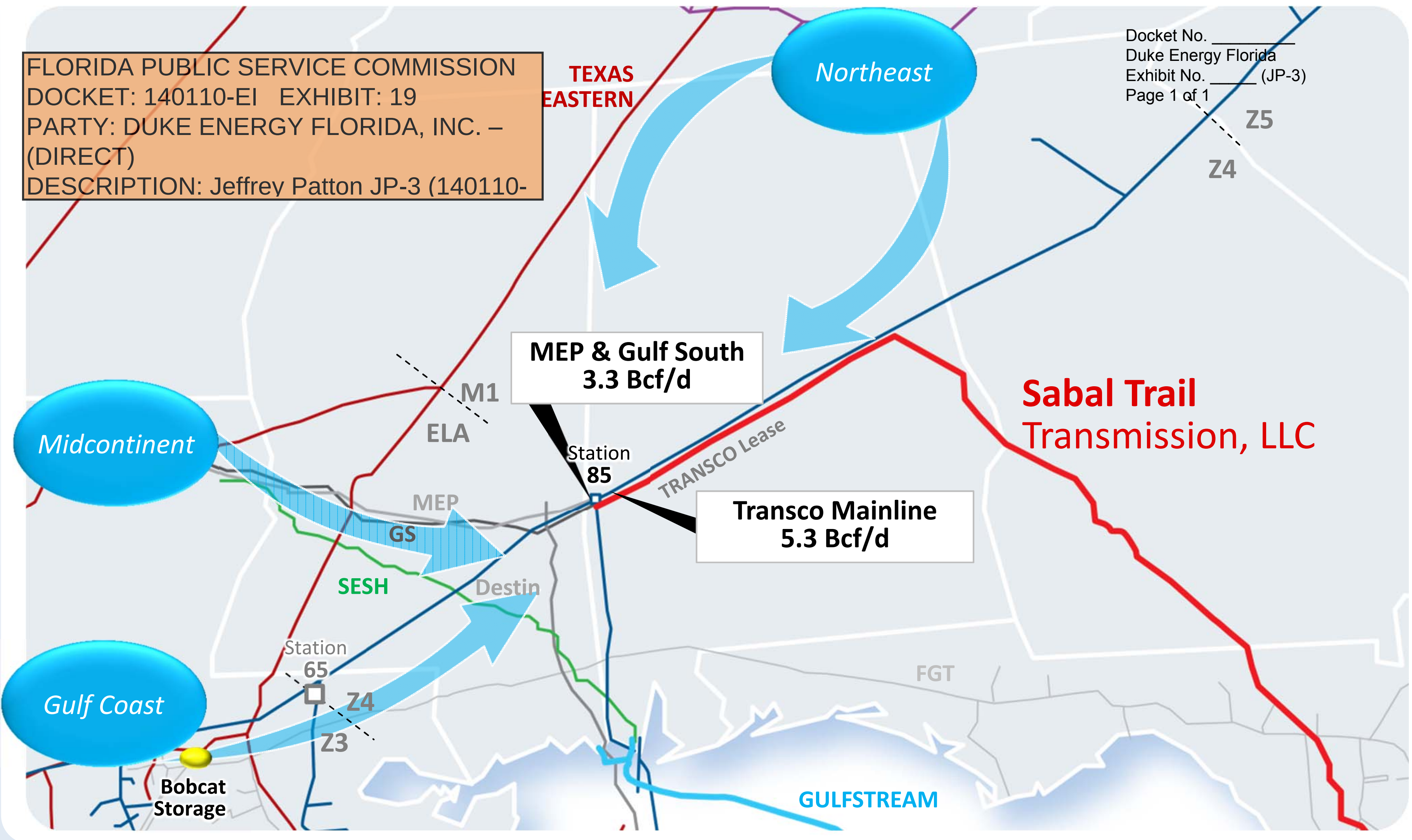

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 20
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Jeffrey Patton JP-4 (140110-

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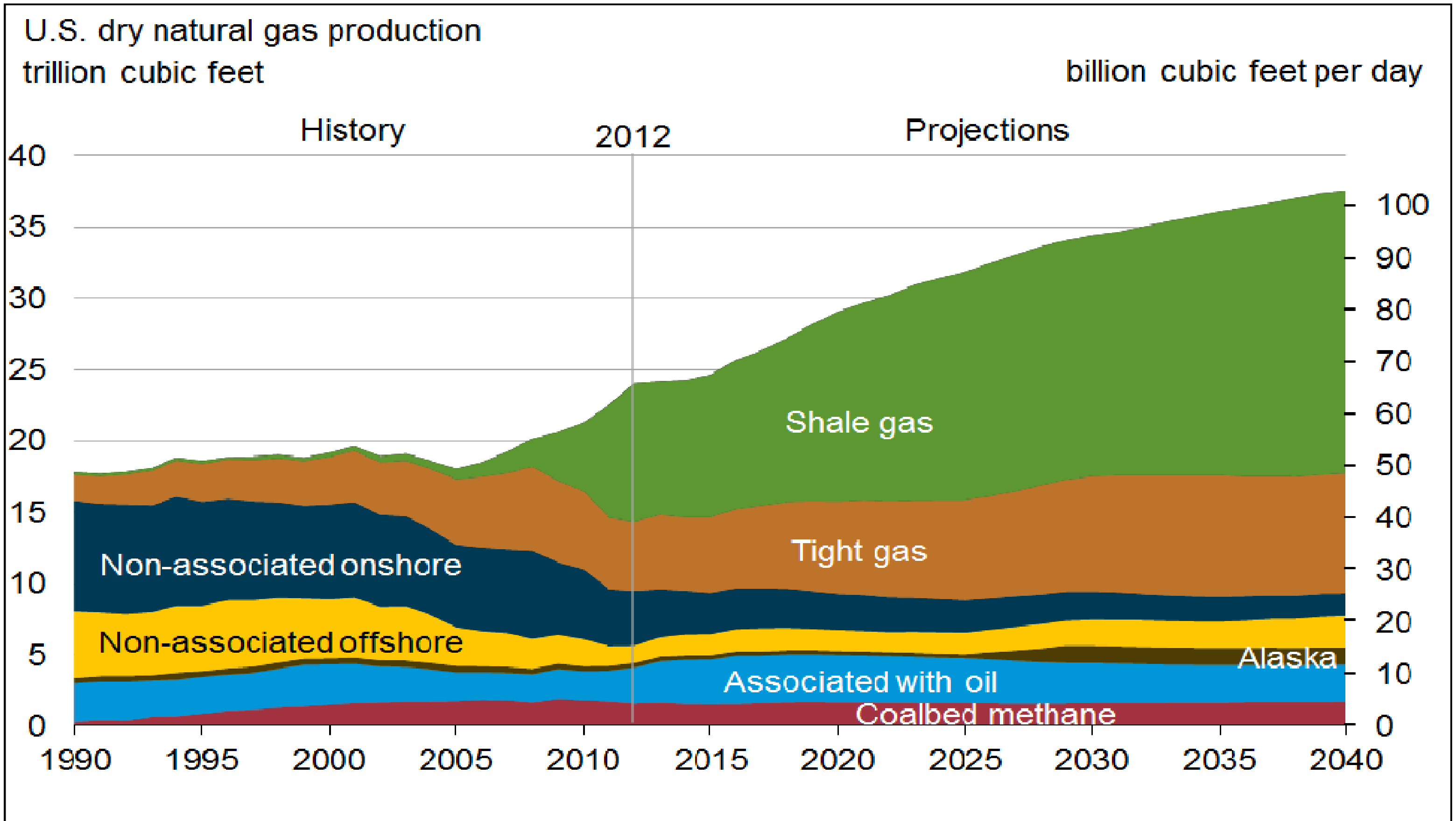

Source: EIA, Annual Energy Outlook 2014, Reference case

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Duke Energy Florida
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Page 1 of 1

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 21
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-1

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Exhibit No. _____ (KD-3)
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 23
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-3

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

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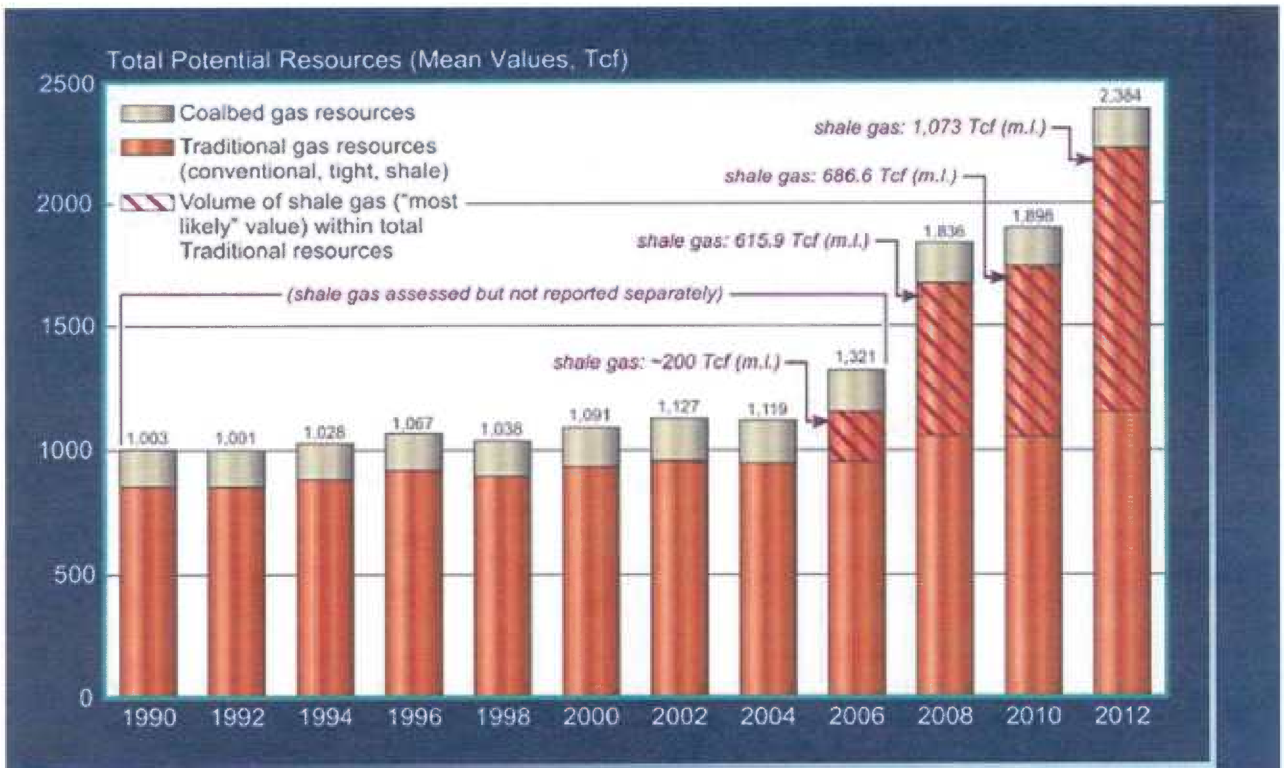
Duke Energy Florida
Exhibit No. ______ (KD-4)
Page 1 of 1



Data source: Potential Gas Committee (2013)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 25
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-1

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 26
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-2

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Duke Energy Florida
Exhibit No. _______ (KD-2)
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 27
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-3

Docket No. ____________
Duke Energy Florida
Exhibit No. _____ (KD-3)
Page 1 of 1

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 28
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Kevin Delehanty KD-4

Docket No. __________
Duke Energy Florida
Exhibit No. ______ (KD-4)
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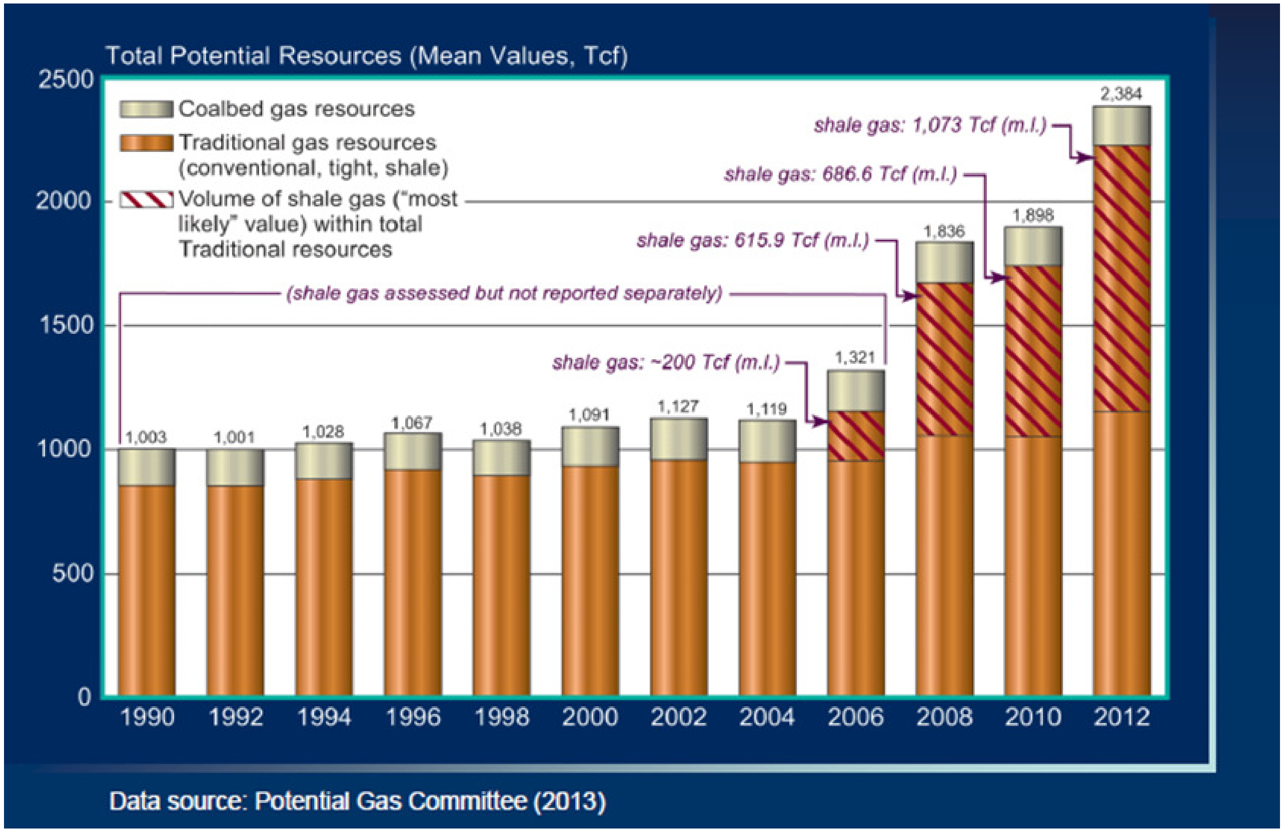


FRCC
Florida Reliability Coordinating Council, Inc.

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**

Table of Contents

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.

<u>Deliverable 2 - Transmission impacts and potential solutions in 2016 & 2017</u>

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.

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.

Docket No. ______________
Duke Energy Florida
Exhibit No. ______ (ES-2)
Page 1 of 1

REDACTED

RFP Transmission Resource Plans Groups

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 30
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Ed Scott ES-2 (140110-EI)

REDACTED

2A

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 31
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Ed Scott ES-3 (140110-EI)

REDACTED

2B

[redacted]

3A

REDACTED

[redacted]

REDACTED

3B

[redacted]

REDACTED

3C

[redacted]

4A

REDACTED

[redacted]

REDACTED

4B

[redacted]

4C

REDACTED

[redacted]

REDACTED

Summary of Estimated Transmission Cost by Group

[redacted]

REDACTED

[redacted]

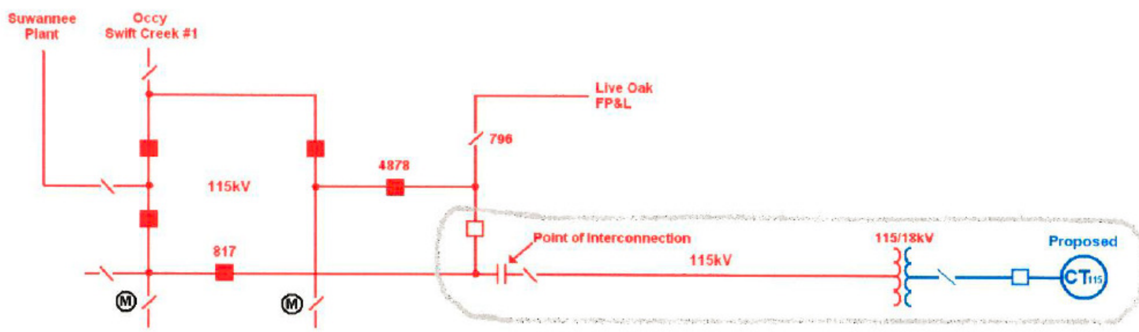
Interconnection Points Evaluated

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.

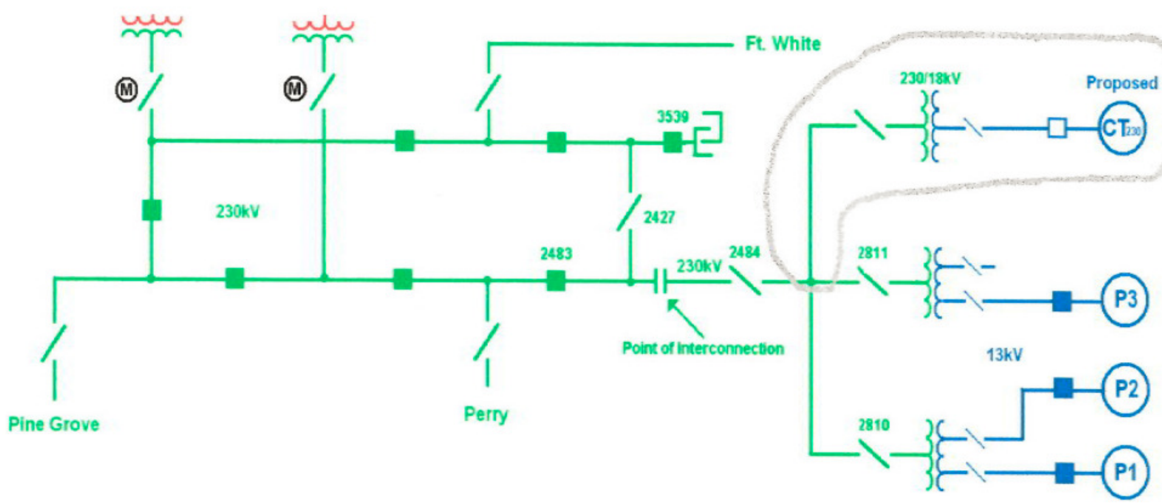


Point of interconnection requested for study by interconnection customer for the 230kV unit:

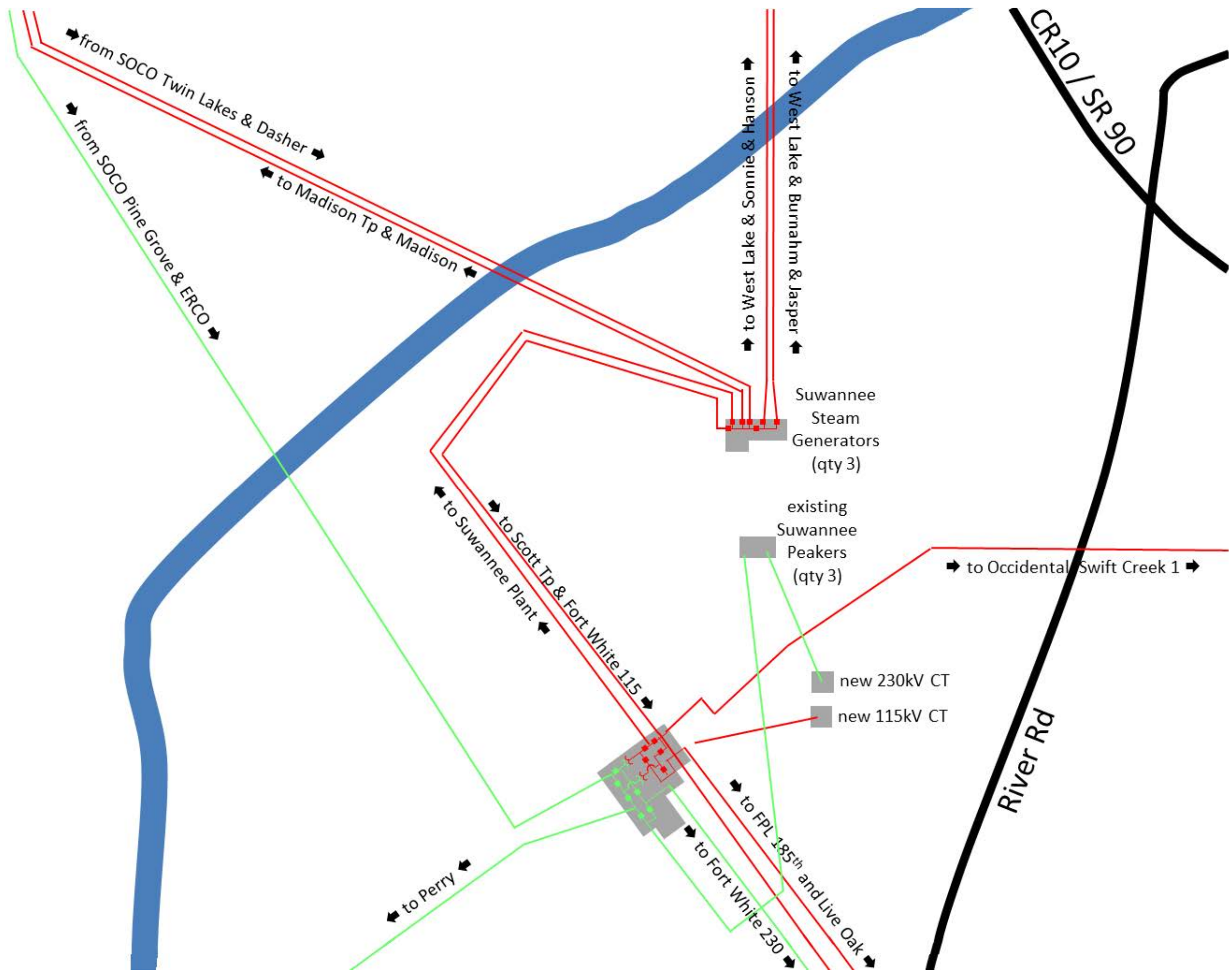
- Connection to DEF's existing Suwannee Peakers 230 kV switchyard..

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

- No other options were considered reasonable or necessary.



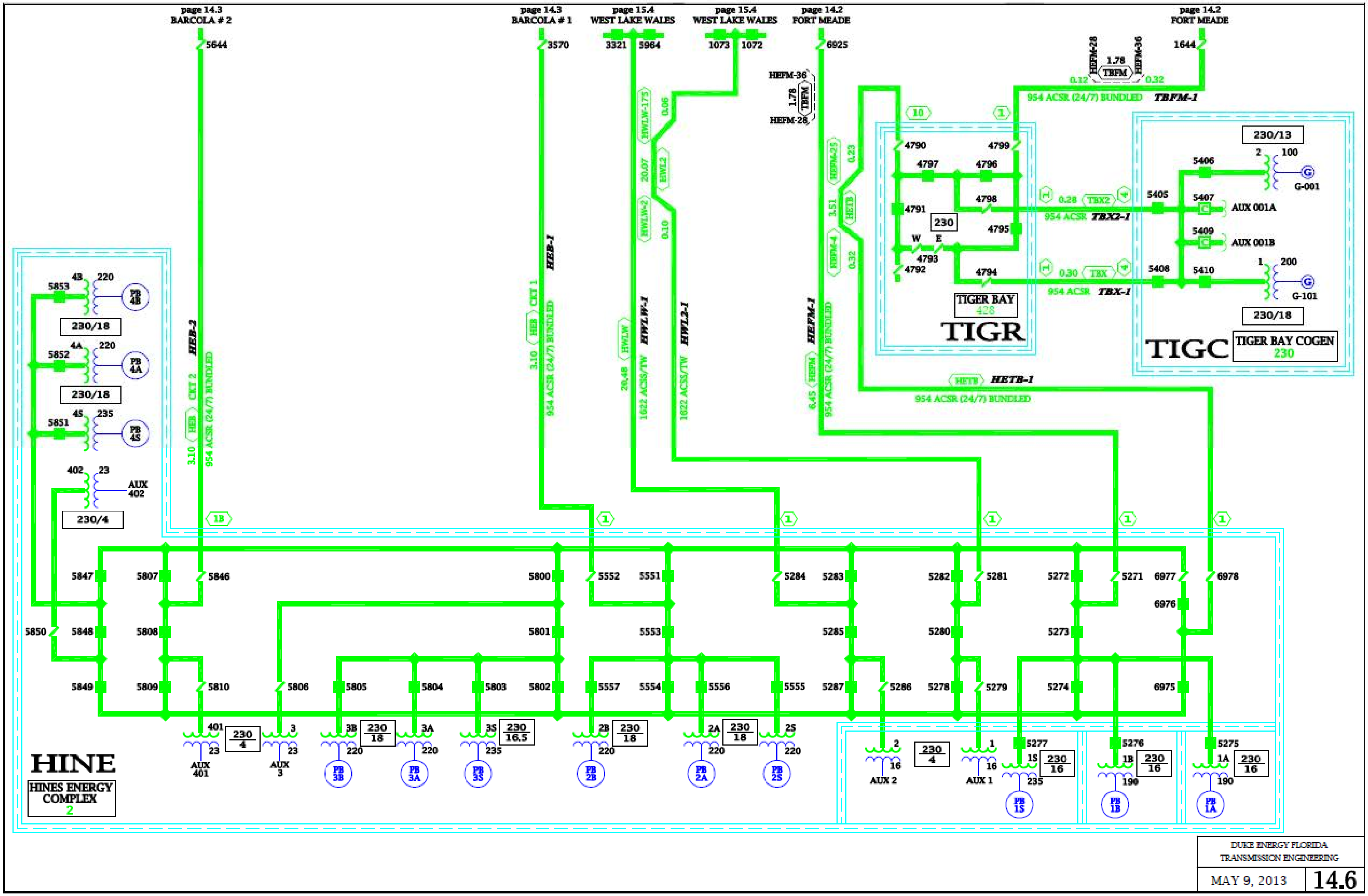
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 32
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Ed Scott ES-1 (140111-EI)


CR10 / SR 90
from SOCO Twin Lakes & Dasher
from SOCO Pine Grove & ERCO
to Madison Tp & Madison
to West Lake & Sonnie & Hanson
to West Lake & Burnahm & Jasper
Suwannee Steam Generators (qty 3)
existing Suwannee Peakers (qty 3)
to Occidental Swift Creek 1
new 230kV CT
new 115kV CT
to Scott Tp & Fort White 115
to Suwannee Plant
River Rd
to FPL 185th and Live Oak
to Fort White 230
to Perry

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 33
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Ed Scott ES-2 (140111-EI)

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



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 34
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Ed Scott ES-3 (140111-EI)

REDACTED

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

[redacted]

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[redacted]

[redacted]

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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		[redacted]		[redacted]

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DOCUMENT 1 OF EXHIBIT AST-1

RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Independent evaluation services for competitive bidding resource selection, integrated resource planning, market analysis, risk assessment, and strategic planning

EMPLOYMENT HISTORY

- President, Sedway Consulting, Inc., Boulder, CO, 2001-present
- Senior Member of PA Consulting, Inc., Boulder, CO, 2001
- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000
- From Senior Associate to Principal, Utility Services Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1991-1999
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Internships at: Pacific Gas & Electric Company, San Francisco, CA (1990)
  Lawrence Berkeley National Laboratory, Berkeley, CA (1989-1991)
  MIT Resource Extraction Laboratory, Cambridge, MA (1982)
  Baltimore Gas and Electric Company, Baltimore, MD (1980)

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases; analyzed thousands of such power supply proposals.
- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Assisted in or monitored contract negotiations with hundreds of shortlisted bidders in utility resource solicitations.
- Testified on utility competitive bidding solicitation results, affiliate transactions, cost recovery procedures, rate case calculations, and incentive ratemaking proposals.
- Managed the development of market price forecasts of North American and European electricity markets under deregulation.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

SELECTED PROJECTS

2013-2014 **California Solicitations for Resources**
Client: Southern California Edison

Currently serving as the Independent Evaluator (IE) in Southern California Edison's (SCE) Local Capacity Requirements Request for Offers (LCR RFO) for 1,900-2,500 MW of new local capacity resources from energy efficiency, demand response, energy storage and/or gas-fired facilities. Also served as the IE for all five of SCE's 2013 reverse energy auctions of the dispatch rights to facilities under power purchase agreements executed with developers of facilities selected in the utility's 2006 New Generation RFO.

2013 **Minnesota Solicitation for New Resources**
Client: Minnesota Power Company

Provided independent evaluation services in a solicitation for 220 MW of wind generation in Minnesota; bids were compared to the utility's proposal to develop its own wind farm.
Mr. Taylor assisted with the development of the request for proposals (RFP), performed a parallel economic evaluation of the utility's facility and all competing proposals, monitored communications and negotiations with shortlisted bidders, and provided a report for filing with the Minnesota Public Utilities Commission regarding the results of the solicitation.

2013 **Kentucky Renewable Resource Analysis**
Client: Kentucky Industrial Utility Customers

Provided expert analysis and testimony on behalf of customers of Kentucky Power regarding a renewable energy purchase agreement for output from a new 58 MW biomass facility that is expected on-line in 2017.

2006-2013 **California Solicitations for Conventional and Renewable Resources**
Client: Southern California Edison

Currently serving or has served as the IE in 23 solicitations for power or gas supplies in southern California – one, as noted above, for SCE's 2013 LCR RFO, an earlier one for over 2,500 MW of new conventional resources, four for renewable energy purchases to help SCE meet its state Renewables Portfolio Standard (RPS) requirements, five for near-term capacity resources, eight for reverse energy auctions of the dispatch rights to facilities under power purchase agreements, and four for gas financial hedging products. Mr. Taylor managed or is managing a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who are/were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2012 **Florida Solicitation for New Resources**
Client: Tampa Electric Company

Served as an independent evaluator in a solicitation for 500 MW of power supplies in Florida. New capacity had to be on-line by 2017; bids were compared to the utility's proposal to repower four existing combustion turbines into a larger combined-cycle facility. Mr. Taylor assisted with the development of the RFP, performed a parallel evaluation of all proposals, monitored communications and negotiations with contracting counterparties, and testified before the Florida Public Service Commission regarding the solicitation's results.

2011 **Minnesota Solicitation for Wind Resources**
Client: Minnesota Power

Provided independent evaluation services in a solicitation for 100 MW of wind generation in Minnesota. Proposals competed with a utility proposal to develop its own wind farm. Mr. Taylor assisted with the development of the RFP and performed a parallel economic evaluation of the utility's facility and all competing proposals.

2005- **California Solicitations for Conventional and Renewable Resources**
2010 Client: Pacific Gas & Electric

Served as the Independent Evaluator in four solicitations for new power supplies in northern California – one for 2,200 MW of new conventional resources, another for up to 1,200 MW of new generating resources from any source, and two others for between 1,400 and 2,800 GWh/year of renewable energy purchases. Mr. Taylor managed a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2007- **Florida Solicitation for New Resources**
2008 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,250 MW of new power supplies for 2011. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2007- **Avoided Cost Analysis for Interruptible Loads**
2008 Client: Public Service Company of Colorado

Provided an independent assessment of Public Service Company of Colorado's peaking resource avoided costs for use in the utility's development of customer credits for its interruptible service tariff.

2007- **Florida Solicitations for New Resources**
2008 Client: Tampa Electric Company

Provided independent evaluation services in two separate Tampa Electric Company solicitations for 600 MW of new power supplies for 2013, as a market test for the utility's proposals to develop initially an integrated gasification combined cycle (IGCC) facility and later a gas-fired combined cycle facility.

2004- **Regulatory Support of Commission Staff**
2005 Client: Utah Division of Public Utilities

Assisted staff for the Utah Division of Public Utilities in the division's efforts to analyze PacifiCorp's 2005 rate case. Mr. Taylor reviewed production cost modeling results and forecasts of system-wide fuel and purchase power costs.

2004- **Minnesota Solicitation for New Resources**
2005 Client: Minnesota Power

Provided independent evaluation services in a solicitation for 200 MW of firm power supplies. Mr. Taylor reviewed all proposals and performed a parallel economic evaluation among proposed turnkey facilities and power purchases.

2004 **Canadian Solicitations for Conventional and Renewable Resources**
Client: Ontario Energy Ministry

Participated in a broader consulting team and provided assistance in the development of RFPs for 2,500 MW of conventional resources and 300 MW of renewable resources. New long-term sources of power were sought to replace regional coal-fired generation.

2003- **Florida Solicitation for New Resources**
2004 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,100 MW of new power supplies for 2007. Mr. Taylor performed a parallel economic evaluation of all proposals and reviewed, cross-checked, and corrected (where necessary) the utility's analyses. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2002- **Minnesota Solicitation for New Resources**
2003 Client: Northern States Power

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2005-2009 time frame. Mr. Taylor was the independent evaluator in two separate solicitations. He managed a team of individuals in the evaluation of responses for both Requests for Proposals (RFPs). In the first solicitation, contingent proposals were received that could serve as replacement contracts for 1,100 MW of nuclear capacity if NSP were forced to decommission its Prairie Island power plant in 2007. In the second solicitation, NSP sought approximately 1,000 MW of new supplies to supplement its existing supply portfolio. The evaluation included the review of over a dozen proposed wind projects.

2002 **Florida Revisions to Bidding Rule**
Client: Consortium of utilities

Provided the Florida Public Service Commission with recommendations concerning appropriate revisions to the state's bidding rule. Mr. Taylor participated in public workshops to provide the benefits of his extensive experience in performing competitive bidding solicitations and to convey what changes should or should not be made to Florida's existing bid rule to ensure the selection of the best resources for the state's electricity customers.

2002 **Arizona Testimony Concerning Competitive Bidding Solicitations**
Client: Harquahala Generating Company, LLC

Filed testimony before the Arizona Corporation Commission in the Generic Proceedings Concerning Electric Restructuring Issues and Associated Proceedings. Mr. Taylor's testimony provided the Commission with information about competitive bidding processes that he had seen work in other states. Also, his testimony addressed various concerns that were raised by Arizona Public Service as to the feasibility of implementing competitive bidding in Arizona.

2002 **Florida Solicitation for New Resources**
Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,750 MW of new power supplies in the 2005-2006 time frame. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. Also, he provided suggestions on resource optimization modeling approaches that ensured the most comprehensive examination of thousands of potential combinations of proposals.

2001 **Wisconsin Testimony Concerning Competitive Bidding Solicitations**
Client: MidWest Independent Power Suppliers

Provided testimony in a proceeding before the Wisconsin Public Service Commission on behalf of a consortium of independent power producers. Mr. Taylor testified on the benefits and timing of a competitive bidding solicitation that Wisconsin Electric Power Company (WEPCO) should be ordered to conduct prior to the utility's development of $2.8 billion in self-build generation facilities (embodied in a WEPCO proposal called Power the Future – 2). Without the benefits of a competitive solicitation, there would be no defensible means of ensuring that the utility's customers were being offered the best, most cost-effective resources.

2001 **Negotiation of Full-Requirements Purchase Contract**
Client: Georgia cooperative utility

Assisted in negotiation of a $2 billion power purchase contract. Mr. Taylor worked with a team of legal experts and other consultants to assist the client in negotiating a 15-year full-requirements contract with a large, national power supplier. Detailed modeling simulations were performed to compare the complex transaction to the utility's own self-build alternatives. Mr. Taylor helped investigate and negotiate detailed provisions in the power supply contract concerning ancillary services and other operational parameters.

2001 **Evaluation of Resource Proposals**
Client: North Carolina municipal utility

Reviewed responses to a utility resource solicitation and assisted the client in developing a short list of the best bidders. Mr. Taylor reviewed the results of the client's economic analysis of the proposals and provided insights on various nonprice factors related to each of the top-ranked proposals. Mr. Taylor helped the client in structuring and strategizing for the negotiation process.

2000- **Solicitation for New Resources**
2001 Client: Public Service of Colorado

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2002-2005 time frame. Mr. Taylor managed a team of a dozen individuals who performed economic and nonprice evaluations of conventional and renewable proposals. Mr. Taylor developed recommendations for a short list of the best resources and managed a supplemental evaluation of second-tier bidders when the client's capacity needs subsequently increased. Ultimately, over $2 billion of contracts were negotiated for over 1,700 MW of new power supplies under terms of up to 10 years. Mr. Taylor testified before the Colorado Public Utilities Commission on the processes and results of both the primary and supplemental evaluations.

1999- **Solicitation for New Resources**
2000 Client: MidAmerican Energy

Reviewed MidAmerican's solicitation for new power supplies for the 2000-2005 resource planning period. Mr. Taylor managed a team of individuals who performed an independent parallel evaluation of MidAmerican's analysis of responses to the utility's request for proposals (RFP). Mr. Taylor reviewed MidAmerican's evaluation and negotiation process and testified to the fairness and appropriateness of MidAmerican's actions. He filed testimony before the utility regulatory commissions in Iowa, Illinois, and South Dakota.

2000 **Electricity Market Assessments**
Client: various American and European clients

Helped develop electricity market prices for regional electricity markets in North America (California, New England, Arizona/New Mexico, Louisiana) and Europe (Austria, Belgium, France, Germany, and the Netherlands). Mr. Taylor worked with project teams in the U.S. and Europe to develop simulation models and databases to forecast energy and capacity prices in the deregulating power markets.

1999 **Evaluation of New Resources**
Client: Florida Power Corporation

Helped prepare the FPC's RFP for long-term supply-side resources and assisted in the independent evaluation of responses. Mr. Taylor oversaw the review of FPC's computer simulations (in PROVIEW and PROSYM) of the proposals that were received. The project team also evaluated the proposals by using a response surface model to approximate the results that might be produced in the more detailed simulations. Mr. Taylor testified before the Florida Public Service Commission concerning his assessment of FPC's solicitation and the results of the analysis.

1998 **Evaluation of New Resources**
Client: Public Service of Colorado

Assisted the evaluation of proposals for PSCo's near-term 1999 resource additions and managed the complete third party evaluation of proposals for resources in the 2000-2007 time frame. Such resources included third-party facilities and power purchases, as well as company-sponsored interruptible tariffs. Mr. Taylor assisted with the development of the request for proposals and oversaw the evaluation of all responses. He and his team monitored subsequent negotiations with shortlisted bidders. Mr. Taylor testified before the Colorado Public Utilities Commission on the fairness of the solicitation and the results of the evaluation.

1997- **Evaluation/Negotiation of Transmission Interconnection Solicitation**
1999 Client: New Century Energies

Managed a solicitation for participation in a major transmission project interconnecting Southwestern Public Service (a Texas member of the Southwest Power Pool) and Public Service of Colorado (a member of the Western Systems Coordinating Council). As the first major inter-reliability-council transmission project in the era of open access, FERC required that SPS and PSCo solicit third-party interest in participation. This project required the development of an RFP and evaluation of responses for both equity participation and long-term transmission service for over 21 alternative high-voltage AC/DC/AC transmission projects. The evaluation focused on the costs and intangible risks of different transmission alternatives relative to the benefits and savings associated with increased economy interchange, avoided future generating capacity, and reductions in single-system spinning reserve and reliability requirements.

1996- **Evaluation/Negotiation of All-Source Solicitation**
1997 Client: Southwestern Public Service

Managed the evaluation of a broad array of responses to an all-source solicitation that was issued by Southwestern Public Service (SPS). Resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads were proposed. The evaluation entailed scoring the proposals for a variety of price and nonprice attributes. Mr. Taylor assisted Southwestern in its negotiations with the bidders and performed the detailed evaluation of the best and final offers.

1996- **Risk Assessment for 1,000-MW Solicitation**
1997 Client: Seminole Electric Cooperative

Managed the review and assessment of risks associated with responses to a 1,000-MW solicitation that was issued by Seminole Electric Cooperative. The evaluation entailed reviewing selected proposals' financial feasibility, performance guarantees, fuel supply plans, O&M plans, project siting, dispatching flexibility, and bidder qualifications.

1997 **Analysis/Testimony - Louisville Gas & Electric's Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Louisville Gas & Electric's (LG&E) fuel adjustment clause and identified misallocated costs in the areas of transmission line losses and purchased power fuel costs. Mr. Taylor also critiqued LG&E's rate adjustment methodology and recommended closer scrutiny of costs associated with jurisdictional and non-jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1995 **Development of All-Source Solicitation RFPs**
Client: Southwestern Public Service

Managed the development of five RFPs that solicited resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads. The RFPs were issued by SPS as part of an all-source solicitation to identify resources that may be competitive with two generation facilities that SPS intended to develop.

1994 **Development of Competitive Bidding RFP**
Client: Empire District Electric Company

Based on knowledge gained from the review of dozens of other utility RFPs, developed a combined-cycle resource RFP for Empire District Electric Company. The project team was responsible for the RFP's entire development, including the development of scoring provisions for price and nonprice project attributes.

1993 **Selection of Developer for 25 MW Wind Facility**
Client: Northern States Power

Evaluated bids that were received by NSP in a solicitation for the development of a 25 MW wind facility in Minnesota. The proposals were scored and ranked through a point-based evaluation system that was developed prior to the solicitation. The scoring involved an assessment of operational and financial feasibility, power purchase pricing terms, construction schedules, and community acceptance issues.

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR DUKE ENERGY FLORIDA'S 2013 POWER SUPPLY SOLICITATION

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

May 21, 2014

REDACTED

Introduction and Background

On October 8, 2013, Duke Energy Florida, Inc. (DEF) issued a Request for Proposals (RFP) for 2018 capacity and energy from resources that might be more cost-effective for its customers than its Next Planned Generating Unit (NPGU) – a 1,640 MW combined-cycle (CC) facility proposed to be sited in Citrus County, Florida.

Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent monitoring and evaluation services to DEF and provide a parallel economic evaluation of responses to the RFP. This independent evaluation report documents Sedway Consulting's evaluation process and presents the results of Sedway Consulting's economic analysis. It describes:

- the proposals that were received in response to DEF's 2018 RFP,
- Sedway Consulting's proprietary Response Surface Model (RSM) which was used to conduct the parallel economic evaluation,
- fundamental assumptions that were applied, and
- additional economic factors that affected the final cost of each resource.

Receipt of Proposals

In DEF's RFP, bidders were instructed to upload proposals to DEF via a web-based bid submission platform by December 9, 2013 and deliver a copy directly to Sedway Consulting via flash-drives one day later. On or before December 10, 2013, Sedway Consulting received 12 proposals associated with seven projects from five power suppliers (with DEF's NPGU proposal included as one proposal/project/supplier in these totals). All but one of the projects were natural gas-fired technologies. The response to the RFP did not yield enough proposed transactions with enough capacity to match the MWs of DEF's NPGU. However, DEF had declared in the RFP and during the RFP Question & Answer (Q&A) process that it would develop and evaluate sufficiently-sized portfolios of proposals and generic self-build resources. DEF and Sedway Consulting therefore undertook the review and evaluation of all of the proposals with that in mind.

The 12 proposals/seven projects entailed the following:

1. [redacted] a [redacted] power purchase agreement (PPA) for capacity and energy deliveries commencing May 1, 2018 [redacted] Hereafter, this proposal will be referred to as Proposal A in the unredacted portions of this report.

2. [redacted] a [redacted] PPA for capacity and energy deliveries commencing May 1, 2018 [redacted] Hereafter, this proposal will be referred to as Proposal B in the unredacted portions of this report.

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3. [redacted]) PPA for capacity and energy deliveries commencing May 1, 2018 [redacted]. The bidder provided alternative proposals for two PPAs of different durations – one of approximately [redacted] with an expiration date of [redacted] and a second of approximately [redacted] with an expiration date of [redacted] Hereafter, these two proposals will be referred to as Proposal C1 (for the shorter PPA) and Proposal C2 (for the longer PPA) in the unredacted portions of this report.

4. [redacted] a [redacted], with three options offered: a [redacted] PPA for capacity and energy deliveries commencing May 1, 2018, a [redacted] PPA for deliveries commencing January 1, 2015, and an asset sale offer. Hereafter, these proposals will be referred to as Proposals D1 (for the 2018 PPA), D2 (for the 2015 PPA) and D3 (for the asset sale) in the unredacted portions of this report.

5. [redacted] a [redacted] with three options offered: a [redacted] PPA for capacity and energy deliveries commencing May 1, 2018, a [redacted] PPA for deliveries commencing January 1, 2015, and an asset sale offer. Hereafter, these proposals will be referred to as Proposals E1 (for the 2018 PPA), E2 (for the 2015 PPA) and E3 (for the asset sale) in the unredacted portions of this report.

6. [redacted]: a [redacted] PPA for capacity and energy deliveries commencing January 1, 2019 [redacted] Hereafter, this proposal will be referred to as Proposal F in the unredacted portions of this report.

7. **DEF's NPGU**: a 1,640 MW (summer capacity) new CC facility to be built in two phases at a proposed site in Citrus County, Florida – with the first 820 MW phase to come on-line by May 1, 2018 and the second 820 MW phase to come on-line by December 1, 2018.

Table A-1 depicts key information for each of the proposals and DEF's NPGU. Specifically, the table includes each resource's:

- first-year summer capacity,
- power plant type,
- year that the PPA or asset transaction is expected to commence deliveries,
- PPA term (or economic life in the case of asset transaction),
- levelized capacity price or capital-related revenue requirement plus fixed operation and maintenance (O&M) price/charges (over the PPA term or asset life)
- full load heat rate (averaged over the PPA term or asset life), and
- levelized variable O&M charge.

REDACTED

For Proposal C, the shorter-term PPA (i.e., Proposal C1) was found to be more cost-effective than the bidder's longer-term option. For Proposals D and E, the primary PPA proposals (i.e. Proposals D1 and E1, with start dates in 2018) were found to be the most cost-effective offers among those associated with each of those facilities. Thus, the table includes statistics for those best proposal options.

Table A-1
Summary of Proposals and DEF's NPGU

Resource	Sum. Cap. (MW)	Type	Start Year	Term/ Econ. Life (yrs)	Cap. Price ($/kW-mo)	Full Load Heat Rate (Btu/kWh)	Var. O&M ($/MWh)
Proposal A	[redacted]	[redacted]	2018	[redacted]	[redacted]	[redacted]	[redacted]
Proposal B	[redacted]	[redacted]	2018	[redacted]	[redacted]	[redacted]	[redacted]
Proposal C1	[redacted]	[redacted]	2018	[redacted]	[redacted]	[redacted]	[redacted]
Proposal D1	[redacted]	[redacted]	2018	[redacted]	[redacted]	[redacted]	[redacted]
Proposal E1	[redacted]	[redacted]	2018	[redacted]	[redacted]	[redacted]	[redacted]
Proposal F	[redacted]	[redacted]	2019	[redacted]	[redacted]	[redacted]	[redacted]
NPGU	1,640	CC	2018	35	8.64	6,730	3.35

It is important to note that the levelized capacity price for DEF's NPGU in Table A-1 includes all capital costs (for generation and transmission investments) and fixed O&M costs. Unlike the NPGU, none of the bid information in Table A-1 includes transmission costs – all of which were calculated as described later in this report and subsequently added to the bid costs.

Disqualification Decisions

Sedway Consulting reviewed all of the proposals to ensure that they met the RFP's threshold requirements. Although there were a few areas where some proposals may not have completely met a strict interpretation of the RFP's requirements, DEF and Sedway Consulting agreed to defer these concerns and proceed with the evaluation of all proposals and consider these issues in a qualitative assessment later, if necessary. Thus, no proposals were disqualified.

Evaluation Process

Through its review of the proposals that Sedway Consulting received during the bid submission process, Sedway Consulting extracted the following economic information for each proposal (including DEF's NPGU):

- Capacity (winter and summer; base and duct-fired, where applicable)
- Commencement and expiration dates of contract
- Capacity pricing (or asset sales price, if applicable)
- Fixed O&M pricing or charges
- Firm fuel transportation assumptions
- Fuel pricing or indexing
- Heat rate (base and duct-fired, where applicable)
- Variable O&M pricing or charges
- Start-up costs and fuel requirements
- Expected forced outage and planned outage hours
- Third-party transmission costs.

The remainder of this report section addresses the following topics:

- a description of the RSM and its evaluation process,
- the use of a "back-fill" resource in evaluating proposed transactions that expire before the end of the study period,
- proposal/resource cost computation (and costs that were developed outside of the RSM),
- the use of "side-fill" resources to supplement proposals/portfolios so that the resulting portfolios have the same capacity as DEF's NPGU, and
- the process of developing final cost estimates for all resources.

RSM Evaluation Process

The economic information for all outside proposals and DEF's NPGU was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each resource on DEF's system production costs. The RSM calculated each option's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each option, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period. In addition, Sedway Consulting's analysis accounted for the different sizes of resources by supplementing those resources with generic resource capacity. For those resources and scenarios where a resource/portfolio did not fully match the capacity of DEF's NPGU, a per-MW cost of a new generic current-technology CC was added to the resource's costs to cover the difference.

An option's net cost was a combination of fixed and variable cost factors. On the fixed side, the RSM calculated annual fixed costs associated with capacity payments (or generation-related revenue requirements), fixed O&M costs, firm gas transportation costs, third-party transmission wheeling charges (where applicable), transmission revenue requirements, and debt equivalence costs (for PPAs). These annual total fixed costs were discounted to mid-2014 dollars.

On the variable cost side, the RSM first developed a variable dispatch charge (in $/MWh) for each option for each month. This charge was calculated by multiplying the option's heat rate by the specified monthly fuel index price and adding the variable O&M charge.

The RSM then estimated DEF's system production costs for each month and each option by interpolating between production costs estimates that were extracted from a set of runs from EPM – DEF's detailed production cost model. These runs were performed at the start of the project and were used to calibrate the RSM by varying the monthly variable dispatch charge for a proxy proposal and recording the resulting DEF system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated DEF's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 15,000 Btu/kWh. Thus, for each option, the RSM yielded estimates of the annual production cost savings that DEF would be projected to experience if the utility selected the resource option, relative to acquiring the same sized transaction but at the high reference resource dispatch rate. The lower an option's variable dispatch charge, the greater the production cost savings.

Back-Fill Resource

As was mentioned earlier, the RSM accounted for the costs of replacing capacity for all proposed contracts that expired before the end of the study period (2053). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a consistent and appropriate comparison of the value of proposals that had varying contract durations. In effect, by supplementing each short-term proposal with a back-fill resource for the later years, the RSM was simulating what DEF would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity that was roughly equal to that expired resource.

As the basis for cost assumptions for the back-fill resource, Sedway Consulting (and DEF) decided to use a generic future CC resource with the operating efficiencies of the advanced technologies that are available (currently at a higher price) in the development pipeline. Sedway Consulting assumed that the $/kW fixed cost assumptions (e.g., capital-related revenue requirements and fixed O&M costs) would be the same as DEF's standard technology generic CC assumptions that were publicized in the RFP's Q&A process. However, the variable cost assumptions (e.g., heat rates, variable O&M costs, fuel supply issues) were based on the capabilities of the advanced technology facilities. Thus, the underlying assumption was that the advanced technology benefits will be available at traditional technology prices in the time-frame that the back-fill resource would be used. All capital-related costs and variable O&M costs were escalated by 2.5%/year. In addition, Sedway Consulting employed a methodological variation, whereby the RSM scaled the replacement capacity to exactly equal the size of the expiring proposal resource. Thus, all PPA proposals enjoyed the benefit of being replaced at the end of their terms with a resource that exhibited the operating efficiencies and economy-of-scale benefits of an advanced CC plant. In other words, if a 200 MW proposal ended in 2033, the RSM assumed that a 200 MW CC facility replaced it in 2034; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW combined-cycle plant, but rather, they were a prorated portion of the construction costs of a larger (793 MW) advanced CC facility.

As noted above, depending on the "in-service date" for the back-fill resource, the back-filler's capital costs were escalated from a 2018 base-year value by 2.5%/year. This escalation assumption represented DEF's estimate of how construction costs were likely to increase for its generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using DEF's declining revenue requirements profile for the recovery of capacity costs, Sedway Consulting used an escalating pattern that yielded the same long-term present value of revenue requirements. A traditional revenue requirements profile results in the highest capital charges in a project's early years. Thereafter, the capital-related charges decline. This is the opposite from what is usually seen in most power purchase proposals in power supply solicitations. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore restructured the filler's profile of capacity costs to match what is generally seen in the marketplace. This meant that the filler's first year's capacity costs were the lowest, with each year thereafter escalating at 2.5%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the traditional declining revenue requirements profile. Both profiles have the same present value.

Over the full 35 years, the restructuring of the back-fill resource's capacity costs made no difference to the present value of the facility's revenue requirements. However, in the evaluation of outside proposals that did not extend through the end of the study period, it provided a more favorable basis for such proposals' evaluation and captured the appropriate end-effects of post-2053 costs. In effect, it assumed that, following the expiration of an outside proposal's term, DEF would procure replacement power supplies at a trended price based on the advanced CC resource. In reality, if the advanced CC resource as a utility-build resource was determined to be most cost-effective at this future decision point, the declining revenue requirements profile would represent the actual annual costs that DEF's customers would likely pay.

Figure A-1
Comparison of Capacity Cost Profiles

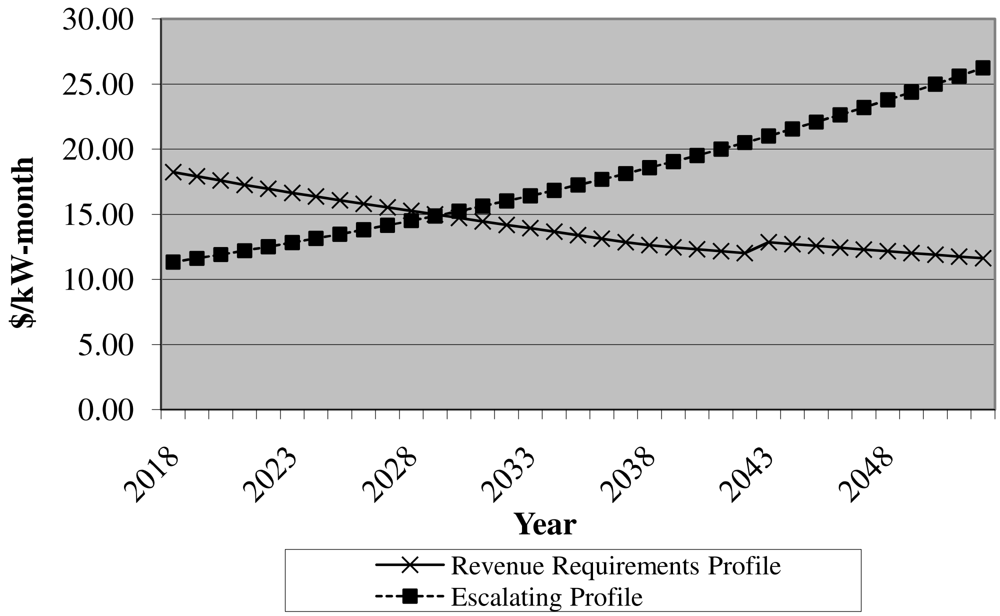
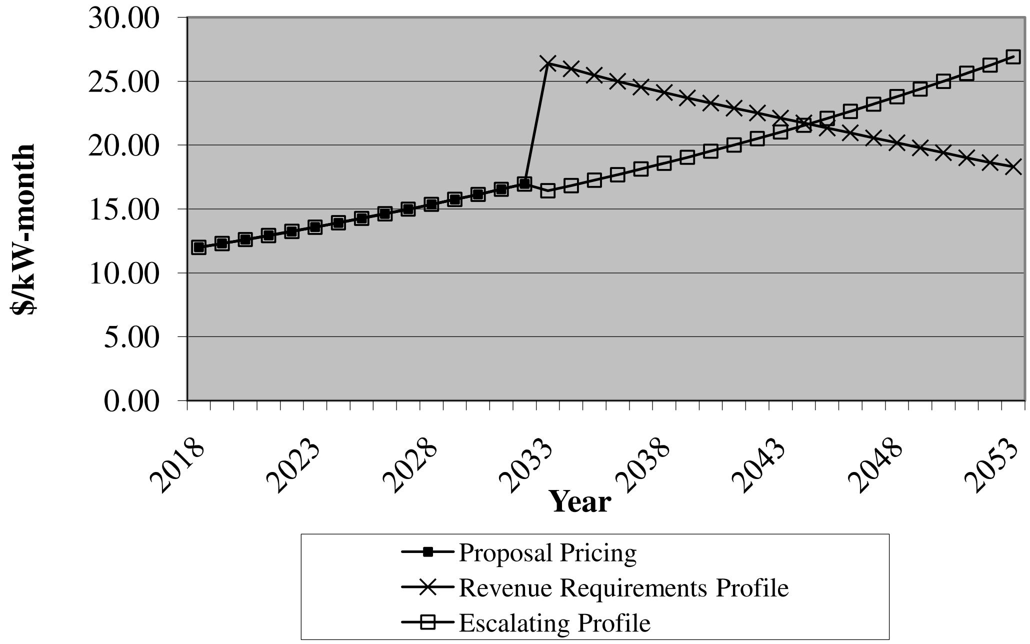


Figure A-2 depicts a comparison of the two approaches for replacing a hypothetical 15-year proposed power supply contract. The proposed contract is assumed to have a capacity charge that begins at $12/kW-month and escalates at 2.5%/year.

Relative to the declining revenue requirements methodology, the escalating filler capacity cost methodology favors the 15-year proposed power supply because it defers the most expensive years of capacity costs until beyond the end of the study period. Thus, the present value of total study-period capacity costs (i.e., power supply proposal plus filler resource) is lower under the escalating filler methodology than under the declining revenue requirements methodology. Ultimately, the use of different filler methodologies by Sedway Consulting and DEF provided added value in looking at the evaluation results from two different perspectives and ensuring that the conclusions were supported from either perspective. However, because Sedway Consulting and DEF used these different methodologies, the total net present value differences depicted in the final results were understandably different.

Figure A-2
Comparison of Filler Capacity Cost Methodologies



Proposal/Resource Cost Computation

Sedway Consulting used its own proprietary revenue requirements model to develop estimates of the annual revenue requirements for DEF' NPGU and cross-checked them with those provided by DEF. Both sets of values compared quite closely, with DEF's having a slightly higher cumulative present value of revenue requirements (CPVRR) – by approximately 1%. Because DEF's values were developed from a more detailed model, Sedway Consulting adopted DEF's annual revenue requirements for use in the RSM.

Most of the input assumptions for the proposals and other cost and operational parameters for DEF's NPGU were directly input into the RSM in a straightforward fashion from the proposal submissions. However, the following were some key additional external cost estimates that were developed outside of each proposal and input into the RSM or, in the case of the last item, calculated within the model from a combination of proposal information and DEF financial parameters:

- Firm gas transportation
- Third-party transmission costs
- DEF transmission costs
- Debt equivalence costs.

Firm gas transportation. DEF's RFP required that bidders of gas-fired projects ensure that firm gas transportation would be available for their facilities. In the RFP bid forms/spreadsheets, bidders were asked to provide information that would allow DEF to estimate the expected annual firm gas transportation (i.e., pipeline reservation) charges for each project. Sedway Consulting reviewed DEF's calculations, compared DEF's values to some of its own calculations and ultimately adopted the same or close approximations to DEF's values. Table A-2 shows the normalized average[1] annual firm gas transportation charges (on a $/kW-year basis) that were assigned to each resource/proposal, as well as the normalized CPVRR impact on each proposal's economic evaluation.

In addition to the annual firm gas pipeline reservation charges, DEF estimated fuel price adders for each project's natural gas supply, where applicable. These adders accounted for locational basis differentials and, in some cases, additional firm gas transportation variable charges. These adders resulted in slightly higher delivered gas prices for the gas-fired outside proposals and generic resources than for DEF's NPGU. Sedway Consulting performed a sensitivity whereby all applicable projects were supplied with gas at the NPGU price and found that the CPVRR impact for the outside proposals was not very significant. That impact is depicted in the final column in Table A-2.

Table A-2
Firm Gas Transportation Cost Assumptions and CPVRR Impact

Proposal/Resource	Annual Charges ($/kW-year)	Reservation Charge CPVRR Impact ($/kW)	Fuel Price Adder CPVRR Impact ($/kW)
Proposal A	47	442	39
Proposal B	0	0	0
Proposal C1	59	461	63
Proposal D1	113	1120	40
Proposal E1	114	1123	38
Proposal F	122	1158	38
NPGU	97	1086	0
Side-Fill-May	72	786	104
Side-Fill-Dec	72	755	101
Back-Fill (2040)	75	149	28

[1] For some resources, the annual charges were the same in all years; in other cases, the annual charges stepped up at certain points in time; in those instances, Table A-2 depicts the average value over the term of the proposal.

Third-party transmission costs. For resources outside of DEF's territory, bidders had to identify in their proposals any firm transmission wheeling charges (e.g., for point-to-point transmission service) that would be incurred and passed on to DEF. Table A-3 depicts the assumptions that were provided by the bidders and verified by the evaluation team. Wheeling charges were assumed to remain flat over the duration of the transaction; this was likely to be a conservative assumption.

Table A-3
Transmission Wheeling Cost Assumptions and CPVRR Impact

Resource/Proposal	Annual Wheeling Charges ($M/year)	CPVRR Impact ($M)
Proposal A	0	0
Proposal B	0	0
Proposal C	0	0
Proposal D	3.1	37
Proposal E	0	0
Proposal F	2.5	23
NPGU	0	0

DEF transmission costs. With the addition of new generation to a utility system, portions of the utility's transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. For proposals that were outside of DEF's transmission system, bidders were responsible for including the costs of such network upgrades to the other transmission provider's system in their bid pricing. However, with regard to DEF's transmission system, any proposal for generation supplies – whether located within or outside of DEF's system – might trigger the need for DEF network upgrades. Estimates of such investments were calculated by DEF's transmission department for specific portfolios of potential resources. Sedway Consulting extracted information from these portfolio transmission estimates and assigned specific portions of the transmission costs to individual proposals. This allowed for an approximation of each proposal's stand-alone costs. However, a portfolio's transmission cost estimate is dependent upon the composition of that portfolio (e.g., size and electrical location of each resource) and cannot necessarily be dissected and isolated to specific proposals or resources. Thus, on an individual project basis, these segmented estimates were entirely Sedway Consulting's decisions and were not supported by DEF's transmission department's analysis. That said, when proposals were recombined back into the studied transmission portfolios, Sedway Consulting ensured that the correct total transmission costs for the portfolio were used. In instances where Sedway Consulting developed a portfolio that had not been studied by DEF's transmission department, the Sedway Consulting results are obviously an approximation based on the dissection process and do not reflect actual study results.

Table A-4 provides the proposal-specific transmission capital estimate derived and used by Sedway Consulting in its stand-alone analysis, as well as the $/kW CPVRR impact on each proposal's economic evaluation.

Table A-4
DEF Network Upgrade Assumptions and CPVRR Impact

Resource/Proposal	Network Upgrades ($M)	CPVRR Impact ($M)
Proposal A	90	96
Proposal B	0	0
Proposal C1	95	83
Proposal D1	54	59
Proposal E1	54	59
Proposal F	54	57
NPGU	40	N/A[1]
Side-Fill-May	30	37
Side-Fill-Dec	30	36
Back-Fill (2040)	30	9

[1]Included in base revenue requirements for NPGU.

Sedway Consulting employed a different methodology than DEF for converting network upgrade capital cost estimates into cost impacts. Sedway Consulting calculated levelized annual transmission revenue requirements[2] for the applicable investment and applied those annual costs only during the term of the PPA (or economic life of the asset in the case of owned generation options). DEF developed revenue requirements from the transmission investment estimates and applied them for all years of the study period for all bids. Neither approach was right or wrong; each was based on slightly different but defensible end-effects assumptions. In any case, the two approaches did not result in significant CPVRR differences in portfolio transmission costs.

Debt Equivalence Costs. Rating agencies view some portion of a utility's capacity payment obligations to a power provider as the equivalent of debt on the utility's balance sheet. If a utility does not rebalance its capital structure by issuing stock, this debt equivalent can negatively impact a utility's financial ratios and cause rating agencies to downgrade their opinion of the utility's creditworthiness. This can increase the utility's cost of borrowing.

Sedway Consulting estimated for each PPA proposal the costs for DEF to rebalance its capital structure if it were to enter into the PPA. This estimate was referred to as a debt equivalence "equity adjustment" because it reflected the present value of the incremental

[2] Assuming a 40-year transmission asset life.

cost of the additional equity that DEF would need to raise to preserve the integrity of its balance sheet. Table A-5 depicts the net present value of the debt equivalence/equity adjustment for all of the proposals.

Table A-5
CPVRR Impact of Debt Equivalence/Equity Adjustment
($M)

Resource/Proposal	CPVRR Impact ($M)
Proposal A	87
Proposal B	9
Proposal C1	68
Proposal C2	98
Proposal D1	17
Proposal D2	18
Proposal D3	0
Proposal E1	15
Proposal E2	15
Proposal E3	0
Proposal F	13

Side-Fill Resource – Portfolio Cost Computation

In Sedway Consulting's analysis, projects were initially evaluated on a stand-alone basis rather than in the context of a long-term generation expansion plan, as was the case with DEF's detailed model. In its final analysis, Sedway Consulting accounted for the different capacity of each resource by developing portfolios of resources (i.e., combinations of bids and generic resource additions) that all were equivalent in size to DEF's NPGU. The proposed NPGU is expected to provide 820 MW (summer capacity) in May, 2018, and another 820 MW by December, 2018, for a total first-year capacity of 1,640 MW. Thereafter, the facility's capacity is expected to experience degradation and average approximately 1,617 MW over its life. Thus, Sedway Consulting developed portfolios that were all 1,617 MW in size, with 820 MW coming on-line in May, 2018, and the remaining 797 MW coming on-line in December, 2018. These portfolios were developed by adding "side-fill" generic resources that were sized to exactly fill out the portfolio capacity. Thus, although these costs were developed from estimates for a 793 MW generic CC, they were smoothly scaled to other capacities.

Using the costs and expected energy benefits of a generic current-technology CC, Sedway Consulting derived a net cost of \$9.09/kW-month for the May, 2018 side-fill resource and \$8.83/kW-month for the December, 2018 side-fill resource.

The inclusion of side-fill resources in the RSM results placed those results on a more comparable footing with the DEF detailed production costing and generation expansion results. DEF used specific generic CCs and CTs as side-fill resources to develop portfolios that were roughly equal to the NPGU.

RSM Evaluation Results

Table A-6 depicts a ranking of all of the resources that were modeled: outside proposals, NPGU, and generic back-fill and side-fill options. The ranking is based on each resource's levelized and normalized $/kW-month net cost.

There are five important things to note in reviewing the RSM ranking. First, the results are based on a stand-alone analysis, are normalized for the size of each resource, and therefore, at this stage, do not match the capacity of DEF's NPGU (except of course for the NPGU itself). Total portfolio effects and cost comparisons are addressed later.

Second, all of the resources have positive net costs because all of them have fixed costs that exceed their benefits. Thus, absent a reliability need, it would not make economic sense for DEF to select any of the resources.

Third, as evidenced by its position near the top of the ranking (in second place), the "Back-Fill" resource was one of the most cost-effective resources modeled – in fact, more cost-effective than DEF's NPGU. Thus, every proposal was provided with the benefits of being back-filled with a very economic resource. All of the proposal results in Table A-6 include the effect of the back-fill resource, with its costs and benefits blended into the depicted levelized net costs. Sedway Consulting believes that this was a generous assumption but an appropriate one. The back-fill resource bolstered the economics of virtually all of the proposals and reflected the possibility that DEF could acquire more advanced technology (than the NPGU) in the future if it were able to satisfy its interim needs with the proposals.

Fourth, all outside proposals – with the exception of Proposal B – were less economic (even with the back-fill resource's beneficial effects) than DEF's NPGU.

Fifth, the table includes May and December pairs of side fill combustion turbine ("CT," i.e., simple-cycle peakers) and CC resources, with the CC resources higher ranked and more cost-effective than the CT resources. DEF and Sedway Consulting discussed this and noted that if a portfolio with side-fill CCs was selected as the best portfolio, that would invariably trigger another RFP through the Florida Bid Rule. Using the side-fill CTs would not have that result. Ultimately, Sedway Consulting decided to use the best side-fill resources to give outside proposals the most cost-effective portfolio partners but recognized that additional scenarios with the side-fill CTs might be warranted if the best portfolio was likely to trigger another RFP. In fact, a single sensitivity using side-fill CTs for the top competing portfolio increased that portfolio's CPVRR by $90 million.

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Table A-6
Ranking of Proposals/Resources
(Cost and Benefit Components of Levelized Net Cost)

Proposal/Resource	First-Year Capacity	Start Date	Capacity & Fixed O&M Cost	Firm Gas Transp. Cost	Transx Cost	Debt Equiv. Cost	Total Cost	Energy Benefits	Levelized Net Cost
	(MW)		($/kW-month)						
Proposal B	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Back-Fill	793	Varies	9.23	5.60	0.35	0.00	15.18	10.03	5.14
DEF Citrus County	1,640	5/1/18	8.64	8.41	0.00[1]	0.00	17.04	9.47	7.57
Side-Fill – CC Dec	793	12/1/18	9.10	5.84	0.35	0.00	15.29	6.46	8.83
Proposal A	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Side-Fill – CC May	793	5/1/18	9.23	5.84	0.35	0.00	15.42	6.33	9.09
Side-Fill – CT Dec	187	12/1/18	4.48	6.02	0.49	0.00	10.99	1.47	9.52
Side-Fill – CT May	187	5/1/18	4.55	6.02	0.49	0.00	11.05	1.43	9.62
Proposal C1	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal C2	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal D1	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal E1	[redacted]	5/1/18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal F	[redacted]	1/1/19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal E2	[redacted]	5/1/15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal D3	[redacted]	1/1/15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal E3	[redacted]	1/1/15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposal D2	[redacted]	5/1/15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] NPGU transmission costs are included in the capacity cost value.

Portfolio Analysis

Based on the RSM results from the stand-alone analysis, Sedway Consulting developed portfolios of proposals and side-fill generic CC resources that amounted to 820 MW in May 2018 and an additional 797 MW in December 2018. This was accomplished with the "Side-Fill – CC May" and "Side-Fill – CC Dec" resources in Table A-6, where the size and associated net costs (i.e., CPVRR over the study period) for these resources were scaled to fill out each portfolio to the 820 MW May and 797 MW December capacity levels in 2018.

Based on this analysis, Sedway Consulting found that DEF's NPGU single-resource portfolio was the least-cost option. Table A-7 depicts the top portfolios and their fixed costs, energy benefits, net costs, and the differences in the net costs relative to that of DEF's NPGU. Each portfolio's net cost is equal to the portfolio's fixed costs minus the portfolio's energy benefits. As described above, the fixed costs include all capacity-related costs (e.g., PPA capacity payments, revenue requirements, fixed O&M costs, firm gas transportation costs, transmission-related costs, and debt equivalence). The energy benefits represent the portfolio's production cost savings relative to the 15,000 heat rate reference resource. The portfolios in the table include the best proposal from each proposed resource, in addition to the best combinations of proposals.

Table A-7
Portfolio Net Costs
($M, $CPVRR_{2014}$)

	Proposal/Portfolio	Fixed Costs	Energy Benefits	Net Cost	Difference from NPGU
1	DEF NPGU	3,611	2,006	1,604	0
2	Proposals A & B	3,311	1,424	1,887	282
3	Proposal B	3,305	1,414	1,890	286
4	Proposal A	3,282	1,373	1,908	304
5	Proposal E1	3,365	1,332	2,033	429
6	Proposal F	3,371	1,329	2,042	438
7	Proposals A, B & C1	3,651	1,607	2,044	440
8	Proposals A & C1	3,610	1,554	2,056	452
9	Proposal D1	3,388	1,326	2,062	458
10	Proposal C1	3,650	1,544	2,106	502
11	Proposals A, D1, E1 & F	3,400	1,270	2,130	526
12	Proposals A, B, C1, D1, E1 & F	3,759	1,502	2,257	653
13	Proposals B, C1, D1, E1 & F	3,790	1,491	2,299	694
14	Proposals D1, E1 & F	3,573	1,260	2,313	709

As noted earlier, all of the proposal portfolios (i.e., Portfolios 2 through 14) included side-fill resources as supplements to the proposals listed in the Proposal/Portfolio column to fill out the size of the portfolio so that each portfolio would be roughly equivalent to the 1,617 MW long-run average capacity of DEF's NPGU. Thus, the information in Table A-7 includes the costs and benefits of appropriately-sized side-fill resources.

On a net present value basis, the NPGU was found to be $282 million less expensive than the next lowest-cost portfolio of alternatives. Sedway Consulting believes that this is a conservative cost differential because of the conservative nature of the analysis, as discussed earlier (e.g., the analytic methodologies that favored PPAs).

Conclusions

Sedway Consulting performed an independent evaluation of DEF's NPGU relative to the responses to DEF's 2018 RFP and concluded that the NPGU represents the lowest-cost resource for meeting DEF's 2018 resource need. The NPGU was found to be $282 million less expensive on a CPVRR basis than the next cheapest portfolio of alternatives.

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 36
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-1 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 37
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-2 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 38
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-3 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 39
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-4 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 40
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-5 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 41
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-6 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 42
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-7 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 43
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-8 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 44
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-9 (140111-

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 45
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-10

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 46
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Julie Solomon JS-11

Docket No. ______________
Duke Energy Florida
Exhibit No. _____ (JS-12)
Page 1 of 1

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	-

NEED DETERMINATION STUDY

In Support of

DUKE ENERGY FLORIDA'S
PETITION FOR DETERMINATION OF NEED
OF CITRUS COMBINED CYCLE UNIT

REDACTED

1. Executive Summary.

Duke Energy Florida ("DEF" or the "Company") plans to add 1640 megawatts ("MW") of electrical generating resources to its system by May 2018 (820 MW) and November 2018 (the remaining 820 MW) in order to continue to provide reliable, adequate, and cost-effective service to its customers. The most cost-effective way for DEF to meet this need is to construct a 1640 MW (summer rating) state-of-the-art natural gas-fired, combined cycle power plant at site adjacent to DEF's existing Crystal River Energy Complex (CREC) in Citrus County, Florida. This unit is called the "Citrus County Combined Cycle Power Plant."

The Company has come to the decision to build the Citrus County Combined Cycle Power Plant ("Citrus CC") unit as the result of its ongoing Resource Planning process involving an extensive analysis of supply-side and demand-side alternatives, based on feasibility, economics, reliability, fuel diversity, and DEF's evaluation of the responses to its Request for Proposal ("RFP") for competitive supply-side alternatives. Duke Energy Florida needs additional generating capacity by the Summer 2018 to (1) maintain system reliability and integrity and continue to satisfy its 20 percent Reserve Margin commitment; (2) continue to provide adequate electricity at a reasonable cost; and (3) ensure appropriate natural gas fuel supply diversity in the Company's supply-side resource mix.

The Company has determined that the Citrus CC will best meet the Company's need for additional generating capacity in 2018. The need for additional generating capacity cannot be cost-effectively deferred or avoided by additional demand-side options. To ensure that DEF will be pursuing the best available alternative, the Company issued an RFP to solicit supply-side alternatives to building the Citrus CC. The Company carefully evaluated resulting proposals based on both price- and non-price attributes. After thorough evaluation, the Company concluded that the Citrus Combined Cycle unit was superior to the competing alternatives offered.

The Company is filing its petition for a determination of need with the Florida Public Service Commission ("PSC" or the "Commission") for approval to build the Citrus CC. This Need Determination Study ("Need Study" or "Study") has been prepared to support the Company's petition to the Commission for a determination of need in conjunction with DEF's application for authority to construct Citrus CC pursuant to the Power Plant Siting Act, sections 403.501 – 403.518, Florida Statutes.

2. Purpose and Overview of Need Study.

Duke Energy Florida is concurrently filing its petition for a determination of need with the Commission for approval to build the Citrus CC. This Need Study is being submitted in support of DEF's petition for a determination of need. It is composed of five main sections and supporting appendices.

The Introduction provides background information on DEF and its generation, transmission, and distribution facilities, as well as the purchased power contracts and demand-side management programs in which the Company is engaged.

The second section provides a description of the proposed Citrus CC. The projected cost and performance of Citrus CC is discussed, and fuel supply, environmental considerations, and transmission requirements are detailed.

The third section of this Need Study describes DEF's need for resources and the identification of the type of resources needed. The section starts with a discussion of the Company's reliability criteria and demonstrates the need for additional generating resources, based on the growing demand and energy requirements of DEF's customers. The Company's determination to seek approval to build Citrus CC is a direct result of the Resource Planning process, which is discussed next. The Company's load and energy forecast, which is an input to this process, is also discussed.

To demonstrate that Citrus CC is the most cost-effective generating alternative, the fourth section describes the Request for Proposals performed by DEF. This section discusses the RFP document, the bids received, and the evaluation performed by the Company.

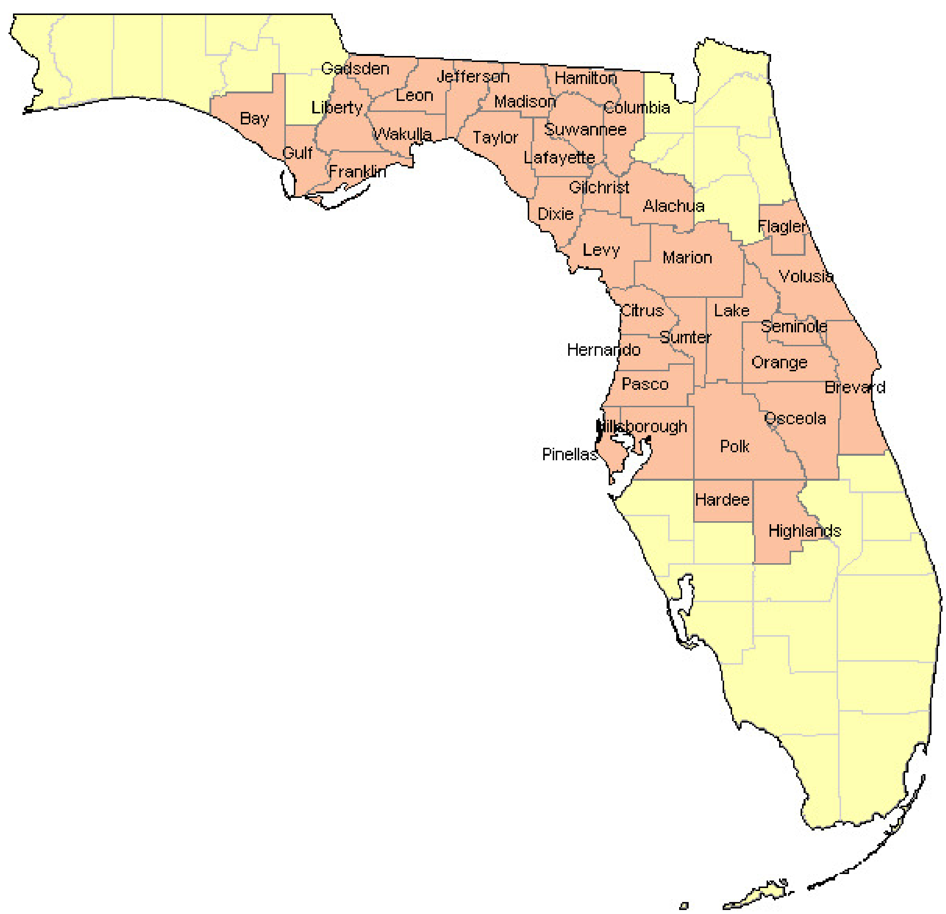
The final section of this Need Study, the Conclusion, summarizes the entire document and demonstrates the need for Citrus CC.

3. Company Description.

DEF is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy").
DEF is an investor-owned public utility, regulated by the PSC, with an obligation to provide electric service to approximately 1.7 million customers in its service area, which covers approximately 20,000 square miles in 29 of the state's 67 counties, as shown on the map in Figure 1. DEF supplies electricity at retail to approximately 350 communities and at wholesale to 22 municipalities, utilities, and power agencies in the State of Florida.

DEF serves what continues to be one of the faster growing areas of the country. Its forecasted annual customer growth is projected to be 1.4 percent over the next 10 years.

Figure 1
Map of Counties Served by DEF



a. Existing Facilities.

DEF currently owns and operates a mix of supply-side resources, consisting of generation from coal, oil, and natural gas, along with purchases from other utilities and purchases from non-utility generators such as cogenerators. The existing generating capacity is listed in Table 1. The Company's existing total summer net owned generating capability is 9,158 MW.

b. Purchased Power.

DEF purchases almost 2,500 MW of capacity from qualifying facilities, independent power producers and investor-owned utilities. The qualifying facilities from which the Company purchases power are fueled by a variety of sources, including natural gas, wood waste, and municipal waste. A full listing of qualifying facility contracts is provided in Table 2. DEF is also engaged in three long-term contracts for power. One contract is with The Southern Company, which sells the Company 414 MW from the coal-fired Scherer and natural gas fired Franklin Plants. DEF also has long term contracts for peaking capacity from the GE Shady Hills facility and the Northern Star Vandolah facility. Altogether, these purchased power resources account for approximately 20 percent of DEF's summer generation capacity, providing a significant amount of diversity in supply.

DUKE ENERGY FLORIDA
EXISTING GENERATING FACILITIES
AS OF MAY 31, 2014

PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL PRI.	FUEL ALT.	NET CAPABILITY SUMMER MW
STEAM						
ANCLOTE	1	PASCO	ST	NG		501
ANCLOTE	2	PASCO	ST	NG		490
CRYSTAL RIVER	1	CITRUS	ST	BIT		370
CRYSTAL RIVER	2	CITRUS	ST	BIT		499
CRYSTAL RIVER	4	CITRUS	ST	BIT		712
CRYSTAL RIVER	5	CITRUS	ST	BIT		710
SUWANNEE RIVER	1	SUWANNEE	ST	NG		28
SUWANNEE RIVER	2	SUWANNEE	ST	NG		29
SUWANNEE RIVER	3	SUWANNEE	ST	NG		71
						3,410
COMBINED-CYCLE						
BARTOW	4	PINELLAS	CC	NG	DFO	1,160
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	462
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	490
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	488
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	472
TIGER BAY	1	POLK	CC	NG		205
						3,277
COMBUSTION TURBINE						
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	24
AVON PARK	P2	HIGHLANDS	GT	DFO		24
BARTOW	P1, P3	PINELLAS	GT	DFO		86
BARTOW	P2	PINELLAS	GT	NG	DFO	42
BARTOW	P4	PINELLAS	GT	NG	DFO	49
BAYBORO	P1-P4	PINELLAS	GT	DFO		174
DEBARY	P1-P6	VOLUSIA	GT	DFO		310
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	247
DEBARY	P10	VOLUSIA	GT	DFO		80
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	45
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	60
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		286
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	328
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		143
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	229
RIO PINAR	P1	ORANGE	GT	DFO		12
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	104
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		51
TURNER	P1-P2	VOLUSIA	GT	DFO		20
TURNER	P3	VOLUSIA	GT	DFO		53
TURNER	P4	VOLUSIA	GT	DFO		58
UNIV. OF FLA.	P1	ALACHUA	GT	NG		46
						2,471
						9,158

DUKE ENERGY FLORIDA FIRM RENEWABLES AND COGENERATION CONTRACTS AS OF MAY 31, 2014				
Facility Name	**Future Contract Start Dates**	**Contract Expiration Date**	**Summer Capacity (MW)**	**Firm Summer Capacity (MW)**
Lake County Resource Recovery		6/30/2014	12.8	12.8
Mulberry		8/8/2024	115	115
Orange Cogen (CFR-Biogen)		12/31/2025	74	74
Orlando Cogen		12/31/2023	115	115
Pasco County Resource Recovery		12/31/2024	23	23
Pinellas County Resource Recovery 1		12/31/2024	40	40
Pinellas County Resource Recovery 2		12/31/2024	14.8	14.8
Ridge Generating Station		12/31/2023	39.6	39.6
Florida Power Development		11/30/2033	60	60
Blue Chip Energy	12/1/2016	N/A	10	
National Solar - Gadsden	12/1/2017	N/A	50	
National Solar - Hardee	6/1/2016	N/A	50	
National Solar - Suwannee	12/1/2017	N/A	50	
National Solar - Highlands	12/1/2017	N/A	50	
National Solar - Osceola	12/1/2017	N/A	50	
Blue Chip Energy - Sorrento	12/1/2016	N/A	50	
E2E2 Inc.	1/1/2017	N/A	30	
US EcoGen Polk	1/1/2017	5/31/2043	60	
TOTAL				**494.2**

DUKE ENERGY FLORIDA PURCHASE POWER AGREEMENTS AS OF MAY 31, 2014			
Facility Name	**Future Contract Start Dates**	**Contract Expiration Date**	**Firm Summer Capacity (MW)**
Northern Star Generation (Vandolah)		5/31/2027	638.8
Shady Hills		4/30/2024	475.7
Southern Company (Scherer)		5/31/2016	342.0
Southern Company (Franklin)		5/31/2016	73.0
Southern Company (Franklin)	6/1/2016	5/31/2021	425.0
TOTAL			**1,954.6**

c. Demand-Side Management ("DSM").

To comply with the directives of the Florida Energy Efficiency and Conservation Act ("FEECA"), DEF must file with the PSC a DSM Plan to meet the conservation goals established by the PSC pursuant to FEECA. The PSC established conservation goals for DEF that span the ten-year period from 2010 through 2019 in Order No. PSC-09-0855-FOF-EG issued December 30, 2009 in Docket No. 080408-EG. The Company filed its DSM Plan on November 29, 2010. However, to avoid undue rate impact on DEF's customers, the Commission, in Order No. PSC-11-0347-PAA-EG, ordered the Company to continue its then-current DSM programs, which were approved as a result of the 2004 goal-setting proceeding. The Commission also approved the implementation of solar pilot programs. A description of Duke Energy Florida's DSM programs, as presented in the ongoing Energy Conservation Cost Recovery docket, is provided in Appendix B. A copy of Order No. PSC-11-0347-PAA-EG, Docket No. 100160-EG, issued on August 16, 2011 is provided in Appendix C.

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.

DEF proposed new conservation goals for the ten year period from 2015 through 2024 in a filing with the Commission as part of Docket No. 130200-EI. Over the next five years (2015-2019) the proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. The proposed conservation goals will lead to an increase in DEF's firm winter and summer peak demand. Therefore, if adopted by the Commission, DEF's proposed DSM goals further establish the need for the Citrus CC.

d. Committed Resources.

On August 1, 2013, the Company filed a Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") dated August 1, 2013, with the FPSC.

One of the Key Provisions of the 2013 Settlement was related to New Generation. Subject to a determination of need from the PSC and a prudence review of investment cost, Duke Energy Florida is permitted to:

- Recover prudently incurred costs to construct, acquire or uprate existing generation of up to 1,150 megawatts of capacity prior to the end of 2017.
- Establish a Generation Base Rate Adjustment (GBRA) to recover additional new generation needs in 2018 of up to 1,800 megawatts.

The Company has two capacity additions in its current Ten-Year Site Plan ("TYSP") prior to the planned in-service date of the Citrus CC.

- Two combustion turbines located at the Suwannee River Site available in June 2016; and
- Additional capacity at the Hines Energy Center through the installation of Inlet chilling that will be in service by 2017.

e. Retirements.

Crystal River Unit 3

On February 5, 2013, DEF announced that it was going to retire the Crystal River Nuclear Plant ("CR3"). The plant had been shut down since late 2009 when delaminations in the outer layer of the containment building's concrete wall occurred during a maintenance outage. The process of repairing the damage and restoring the unit to service resulted in additional delaminations in other sections of the containment structure in 2011. During the ensuing months, DEF evaluated the ability to successfully repair the unit, the risks associated with any repair and the repair scope as well as the likely costs and schedule. A report completed in late 2012 confirmed that repairing the plant was a viable option but that the nature and potential scope of repairs brought increased risks that could raise the cost dramatically and extend the schedule. Ultimately, DEF decided that retiring CR3 was in the best overall interests of its customers, investors, and the state of Florida.

Crystal River Units 1 and 2

Crystal River Units 1 and 2 are not capable of meeting the emissions requirements for the Mercury and Air Toxics Standards ("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 Visibility Rule ("CAVR"), 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 ("FDEP"). 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. To comply with MATS, the units must be de-rated to a collective 740 MW. 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 CC operations.

Other Units

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. DEF also anticipates the retirement of the Avon Park, Rio Pinar and Turner P1 and P2 units. The three 60-year old Suwannee steam units are now projected to retire in the spring of 2016 consistent with the start of operation of the new Suwannee CT units. 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. Current and projected retirements are listed in the table below.

Plant	Summer Capacity (MW)	Existing / Planned	Retirement Date
Crystal River 3	789	Existing	February 2013
Turner 3	53	Planned	December 2014
Turner 1 and 2	20	Planned	June 2016
Avon Park 1 and 2	48	Planned	June 2016
Rio Pinar	12	Planned	June 2016
Suwannee 1 – 3	128	Planned	June 201
Crystal River 1 and 2	740	Planned	April – October 2018 *
Higgins 1 – 4	105	Planned	June 2020

- The specific month of retirement of Crystal River 1 and 2 will be dependent on finalization of commissioning plans for the Citrus Combined Cycle.

f. Transmission and Distribution Facilities.

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.

4. Description of the 2018 Citrus County Combined Cycle Power Plant.

The proposed Citrus CC will be a state-of-the-art, highly efficient combined cycle unit. Its beneficial heat rate, high availability and responsiveness, among other attributes will provide DEF customers with a low-cost, highly flexible source of power. Upon commencement of operation, the Citrus CC will be one of the most efficient natural gas fired units on the Company's system and within the State of Florida. This section outlines the technical characteristics of the proposed facility.

a. General description of the Citrus CC plant.

The Citrus CC will be a natural-gas fired, high efficiency plant that involves the generation of electricity in two stages, first by firing the combustion turbines ("CTGs"), and second by using the hot gas from the CTGs to produce steam through the heat recovery steam generators

("HRSGs") which is fed into the steam turbines ("STGs") to generate additional electricity. This combined-cycle capability makes the most of the input fuel, by burning it and using the waste heat from that process, to generate electricity and, therefore, is a very efficient plant design to produce electrical energy. The combined cycle generation technology is one of the most efficient base load power production technologies available today.

The Citrus CC will be an advanced class gas turbine, 4 by 2 combined cycle configuration, 1,640 MW plant built in stages of 820 MW each, with the first stage in commercial operation in May 2018 and the second stage in commercial operation by December 2018. DEF's technology review determined that use of proven advanced class gas turbines (GAC/H) in a 4X2 configuration will provide the best balance of efficiency, operational flexibility and reliability. The plant will have moderate duct firing capability, which means 50 to 100 MW of duct fired output of each 820MW block will be available as cost effective peaking capacity. The first advanced class turbines of this type in the United States have just been placed in service or are under construction. The Siemens H technology CC plant entered commercial operation in 2013 in Florida by FPL, and the first Mitsubishi GAC technology CC plant is expected to be commercial operation in 2014 in Virginia by Dominion.

The project will not include simple cycle bypass stacks which provide reliability but at a cost to unit efficiency. System reliability will be enhanced by the ability for independent operation of the two power blocks. One 820 MW CC block will connect to the 230kV transmission system and the other 820 MW block to the 500 kV transmission system. The project will take advantage of the existing transmission capacity that is and will be available due to the retirement of Crystal River Units 1, 2, and 3. The project will utilize sea water cooling towers with make-up supplied from the existing CREC intake canal and process makeup water from existing CREC fresh water wells.

The Citrus CC project is designed for single fuel (natural gas only), with moderate duct-firing capability. Natural gas will be supplied via the new Sabal Trail Transmission LLC ("Sabal Trail") pipeline coming into central Florida from Alabama (Transco Station 85) and a new dedicated gas lateral pipeline (with proposed Florida Gas Transmission Company ("FGT") interconnect) to the Citrus CC facility.

b. Project Site.

Siting analysis in 2013 determined the best site for a large combined cycle facility in DEF's territory was near the Crystal River Energy Complex ("CREC") and more specifically a 400 acre parcel, adjacent to CREC, to be purchased from Holcim (US), Inc. ("Holcim"). This location provided clear benefits in terms of the opportunity to utilize existing infrastructure resources including transmission, roads, and water resources. The Project Site is located at approximate latitude 26°58'00.84 north and approximate longitude 82°40'34.58 west.

The site consists of approximately 400 acres of property located immediately and north of the DEF Crystal River to Central Florida 500-/230-kV transmission line right-of-way and east of the Crystal River Units 4 and 5 coal ash storage area. The property consists of regenerating timber lands, forested wetlands, and rangeland. 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 new project is proposing to use the existing CR3 cooling water intake structure and a new discharge structure in the existing discharge canal.

Sources: DeLorme, 2014; ECT, 2014.

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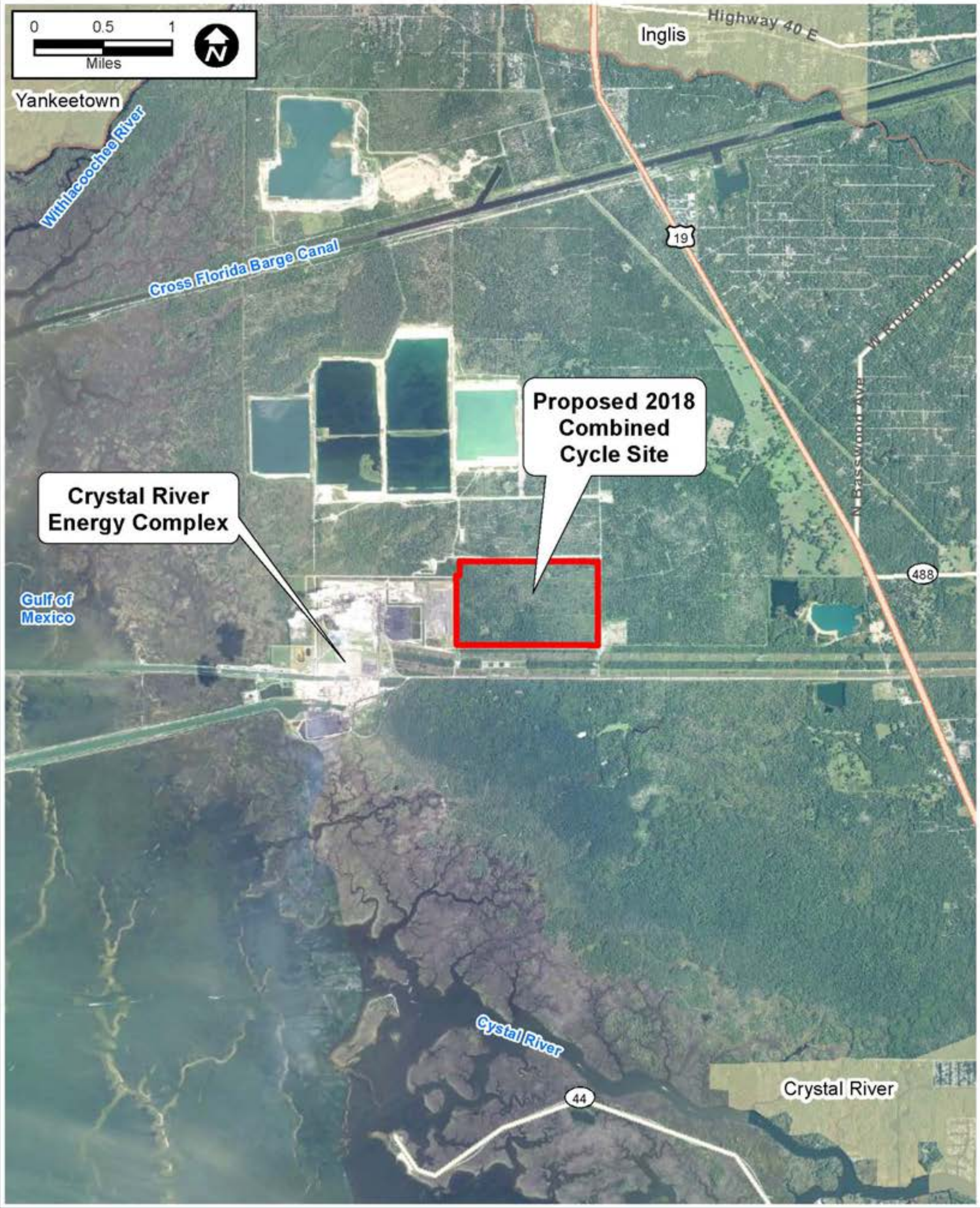

Sources: ESRI, 2013; NAIP, 2013; ECT, 2014.

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c. Detailed Unit Description

The Citrus CC project is a 4x2 1,640 MW power plant using highly efficient advanced technology combined cycle units using natural gas as the fuel with salt water cooling towers as the heat sink. The proposed power block includes four (4) CTs; four (4) HRSGs and two (2) STGs. The power block will be split into two identical 2x1 units (2CTG's, 2 HRSG's, and 1 STG) that can operate as separate units with common infrastructure and provide backup to each other. The design incorporates auxiliary duct firing in the HRSGs to allow for additional steam generation.

The project will include:

- Two (2) units of 2 CT's on 2 HRSG's on 1 ST (2x2x1)
- Each unit has 100% steam by-pass (unfired condition).
- A common control room/administrative building between the two units.
- Separate cooling towers for each unit with common makeup water from the intake canal at CR3.

Major project equipment will include those items below. The description is on a per unit basis unless specified in the description as shared between units.

1. Combustion Turbine Generator Set
   - Advanced Class CT's [G or H]
   - Dry low NOx combustors (15-20 ppm NOx)
   - Hydrogen cooled generators

2. HRSG
   - 3 pressure reheat design
   - 1050F/1050F steam temperatures
   - 2350 PSIA maximum pressure
   - Duct firing capability
   - SCR catalysts
   - Oxidation catalyst for CO and VOC removal
   - Elevator for each unit.

3. Steam Turbine
   - Combined HP/IP Two-flow LP
   - 1050F/1050F steam temperatures
   - 2350 PSIA maximum pressure
   - Hydrogen cooled generator
   - Gantry Cranes for each STG

4. Condenser
   - 100% steam bypass capability for unfired steam flow
   - Deaerating condenser – no external deaerator

5. Cooling System
   - Closed loop salt water cooling tower – using the existing CR3 CW inlet system to supply makeup salt water to cooling towers (common system for the full power block)
   - Two 50% capacity circulating water pumps

6. Main Steam System
   - 100% steam turbine bypass design for unfired steam blow to condenser. Atmospheric vents will be used to minimize the opening of primary relief valves.

7. Feedwater System
   - Two 60% capacity motor operated BFW pumps per HRSG (60% capacity based on unfired case).

8. Condensate System
   - Three 50% capacity Condensate pumps to match cycle requirements
   - Use of the existing CR 1&2 fresh water wells as the source of process makeup water with new water treatment building.

9. Auxiliary Steam/Boiler
   - Single Auxiliary Boiler shared between two units for maintaining STG seals, condenser sparging, and ST prewarming
   - Electric superheaters at each steam turbine

- Auxiliary steam system cross-tied between units.

10. Controls

- Balance Of Plant (BOP) control system, integrated DCS (Emerson Ovation).
- CTG & STG Turbine controls provided by OEM
- Shared control room for the power block in a horseshoe configuration with each side dedicated to a single unit.
- Project includes a high-fidelity simulator system

11. Major Tanks

- Demineralized Water: Two tanks shared between the power block will provide storage for refill and startup of a unit following a single unit HRSG outage.
- Fire Water/Service Water: Two tanks shared between the power block as required to provide service water and fire water for both units. A single fire water supply and fire loop system will be shared by the power block.

12. Electrical Equipment

- GSU for each generator 18kV/230kV for one unit and 18kV/500kV for the other unit.
- UAT and generator breaker for each CTG train within power block
- 13.2 kV / 6,900 Volt medium voltage auxiliary power systems

13. Facilities

- One (1) combined Administration/Control/Maintenance Building with warehouse.
- Two personnel elevators (one on each 2x1) included for access drum-level of HRSG's.
- Drum-level catwalks between HRSG's within each unit.
- The major power equipment shall be outdoor construction.

Projected Citrus CC Costs.

d. Construction Costs.

$M	2013	2014	2015	2016	2017	2018	2019	Total
Engineering, Procurement, Construction, and Major Equipment	-	48.6	174.2	283.8	494.3	96.4	17.4	1,114.7
Owner Cost and BOP Equipment	2.8	11.8	14.3	24.2	89.1	44.1	0.1	186.5
Transmission Switchyard and Bus Line	-	-	-	4.9	41.2	2.4	-	48.5
Annual Cash Flow	**2.8**	**60.4**	**188.6**	**312.8**	**624.6**	**143.0**	**17.6**	**1,349.7**

There are a number of factors why Citrus CC is the most cost-effective alternative. First, DEF is able to take advantage of its prior investment in infrastructure at the CREC. Second, by virtue of its location in Citrus County adjacent to the CREC, the Citrus CC takes advantage of existing transmission capacity available as a result of the generation retirements at the CREC. Finally, DEF has as good, or better, credit rating than many of the IPPs today. Thus, the Company has a financing advantage.

e. O&M costs.

O&M Costs ($M)	2018	2019	2020	2021	2022
Fixed	$5.6	$11.3	$11.6	$12.0	$12.3
Variable (non-fuel)	$12.0	$24.8	$25.3	$26.0	$26.6
Total	$17.6	$36.1	$36.9	$38.0	$38.9

The estimated incremental annual fixed operation and maintenance ("O&M") cost for the Citrus CC is $6.79/kW-Yr (based on winter capacity of the plant and expressed in 2018 dollars). The largest fixed costs are wages and wage-related overheads for the permanent plant staff, as well as expenses for unplanned equipment maintenance. Estimated staffing for the Citrus plant is expected to be at least 40 permanent staff. Variable O&M costs, which vary as a function of plant generation, include consumables, chemicals, lubricants, water, and major maintenance costs such as planned equipment inspections and overhauls. The estimated non-fuel variable O&M cost is $2.41/MWh (expressed in 2018 dollars).

Projected Citrus CC Performance.

The proposed Citrus CC is a high efficiency combined cycle unit. with an expected average annual operational heat rate of approximately 6,625 BTU/kWh. Its heat rate approaches the lowest for generation units in operation today, meaning that it will generate more electricity per unit of fuel than many existing generating plants. The high reliability of the Citrus CC, with an expected equivalent forced outage rate of approximately two percent, will contribute to the Company's ability to provide adequate and reliable service to its customers. The plant's design also allows for greater flexibility in matching DEF's system operating requirements. The Citrus CC can be operated in baseload and load following service on the DEF system, depending on the needs of the system and the prevailing economic conditions. The Citrus CC is expected to operate in a capacity factor range of 50 percent to 90 percent, averaging 67 percent over its expected 35-year life. The Citrus CC will provide DEF and its customers with greater flexibility in the overall operation of its system at a low cost and a leading industry efficiency.

Heat Rate @ Maximum Load (Fully Fired)

Summer	6701	HHV
Winter	6669	HHV

New and clean without any margins applied.

Additional performance and operational characteristics of each unit include:

- Forced Outage Rate: 2%
- Operating ramp rate >20 MW/min
- Minimum load < 200 MW in 1x1 CC mode
- Stable cycle-down operation in 1x1x1 CC mode to obtain minimum load
- Simple-cycle CT operation that precludes combined cycle operation (the plant will be able to operate for a minimum of 30 minutes without the STG on-line bypassing to the condenser.)

The preliminary operational characteristics for the power block from recent production cost modeling are:

Annual Capacity Factor (%) Per Year – 4x2 CC Mode

Unit	**Min**	**Avg**	**High**
4x2 CC	50%	75%	90%

g. Fuel Supply and Transportation.

DEF analyzed the Citrus CC in terms of whether a secure, reliable primary fuel supply existed and could be expected to exist in the future for the plant. Natural gas has emerged as the fuel of choice for the current generation of new power plants because of its environmental advantages compared to coal or oil, its current lower cost and the projected adequate North American supplies available from shale rock sources. The lower level of environmental emissions from gas fueled generation (as compared to coal or oil) will assist DEF in complying with current and future environmental requirements. Recently promulgated and anticipated new regulations including the MATS, New Source Performance Standards for the emission of Greenhouse Gases, and Coal Combustions Residual rules will burden new and existing coal and oil facilities with increasingly larger costs compared to natural gas fired facilities. Federal and State environmental regulations will continue to cause cleaner burning fuels like natural gas to be more in demand as an alternative to coal and oil. Natural gas, therefore, will continue to be an attractive primary fuel source for DEF.

Adequacy of Fuel Supply

In addition to the well-developed conventional natural gas resources along the Gulf Coast and in western North America, 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.” Vast shale rock formations or “shale plays” extend across the United States and Canada. 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 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 Energy Information Administration (“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 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.

In part because of the expansion in natural gas supply in North America, and the forthcoming expansions of transportation into Florida, DEF was confident to design the Citrus CC without simple cycle bypass stacks or back up fuel oil which provide reliability but at costs to unit efficiency and capital construction.

Adequacy of Fuel Transportation

Sufficient and reliable firm gas transportation service for Florida natural gas customers can be expected. In addition to DEF's significant portfolio of firm transportation reservations from the two existing interstate pipelines, Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, L.L.C. ("Gulfstream"), DEF has a precedent agreement for firm transportation on the new Sabal Trail pipeline being constructed to serve the Florida market. Sabal Trail is a joint venture between affiliates of Spectra Energy Corp and NextEra Energy, Inc. The Sabal Trail Project will create a new pipeline system with a planned capacity to transport 1,100,000 dekatherms per day ("Dth/d") of natural gas. The Sabal Trail Project will have an initial capacity of 800,000 Dth/d with an in-service date beginning May 1, 2017. As part of the Sabal Trail Project, Sabal Trail will acquire by lease the mainline capacity to be created by Transcontinental Gas Pipe Line Company, LLC ("Transco"). Transco will expand the existing Transco system from Transco's Station 85 located in Choctaw County, Alabama to a location in Tallapoosa County, Alabama ("Transco Hillabee Project"). Sabal Trail will construct approximately 460 miles of greenfield mainline facilities from the interconnection with Transco in Tallapoosa County, Alabama to a point in Osceola County, Florida south of Orlando at the Central Florida Hub. At or near the Central Florida Hub, Sabal Trail will interconnect with Gulfstream and FGT. Information on Sabal Trail is based on the NEPA Pre-filing Process Request to FERC on

October 4, 2013 made by Sabal Trail for the Sabal Trail Project (Docket No. PF14-1). Additional information on Sabal Trail can be found on their website www.sabaltrailtransmission.com.

The Citrus CC site located in Citrus County, Florida currently is not interconnected with any natural gas pipeline. Sabal Trail will construct a 24-inch diameter gas lateral with an approximate length of 23 miles from Sabal Trail's mainline in Marion County, Florida to the Citrus CC site. The lateral will be capable of providing 300,000 MMBtu/day of firm gas transportation to the 2018CC with the ability to meet potential future additional gas generation needs up to 400,000 MMBtu/day. The gas lateral will have initial pressure above 1,000 psig at the mainline and Sabal Trail has a minimum pressure commitment of 650 psig at the custody transfer point, downstream of the M&R Station serving the Citrus CC. The target in-service date for Sabal Trail to complete the mainline, gas lateral, M&R station and associated facilities to support testing of the Citrus CC is October 1, 2017.

In addition to the previously planned bi-directional interconnections between Sabal Trail and FGT in Suwannee County, Florida and Orange County, Florida, DEF proposes an additional interconnect between Sabal Trail and FGT in Citrus County, Florida. DEF is in discussions with Sabal Trail for a 400,000 MMBtu/day receipt only meter. This interconnect will provide additional pipeline infrastructure diversity and reliability for the Citrus CC. In the event of a pipeline disruption or curtailment on Sabal Trail, this interconnect would allow DEF the ability to optimize FGT to deliver gas supply on a best efforts basis into the gas lateral interconnected with the Citrus CC.

Gas Supply

Sabal Trail provides direct upstream onshore contractual receipt points at Transco Station 85, Gulf South, Midcontinent Express Pipeline (MEP) and the Transco Zone 4 Pool. Gulf South and MEP combine for a receipt capacity of approximately 3.3 Bcf/day from the Mid-continent onshore production areas and can deliver to the proximity of Transco Station 85. These pipelines provide access to gas supplies from the Barnett Shale, Fayetteville Shale, Haynesville Shale, and Woodford Shale. In contrast to the traditional Gulf of Mexico and Mobile Bay offshore gas supplies, which have the risk of curtailment during storms, the "onshore points" at Transco

Station 85 have direct access to pipelines that have access to onshore supplies. This access provides the Citrus CC supply security, availability, supplier diversity, and flexibility. In addition, Sabal Trail provides access to receipt points in the Transco Zone 4 Pool through the lease with Transco which includes additional pipelines.

On average, the Citrus CC will use approximately 195,000 MMBtu (million British thermal units) per day of transportation service (with the capability to use up to 300,000 MMBtu per day in peak operation). DEF's precedent agreement with Sabal Trail, along with its existing agreements and its ongoing activity in the fuel transportation market will allow the Company to provide adequate and competitively priced natural gas transportation to serve the Citrus CC and DEF's fleet of natural gas generating units. The figures below show Florida's current natural gas pipeline network and the proposed path of the Sabal Trail Pipeline.

Fuel Supply Contracts

DEF's forecasted natural gas requirements are expected to be purchased primarily under term supply agreements based on market index pricing, with supplemental seasonal, monthly and daily purchases of natural gas being made as needed.

The FSO – DEF Long-Term Gas Supply RFP Process outlines the Long-Term RFP process by which DEF procures competitively priced natural gas to meet its longer-term projected fuel needs at its owned and tolled gas generation facilities in Florida. For clarity: 1) Long-Term RFP gas procurement activities typically are contract terms greater than one (1) year for periods that will typically begin for the next calendar period for which natural gas supplies are projected to be needed to meet DEF's annual, seasonal, monthly, and/or daily needs at its owned and tolled gas generation facilities; 2) DEF procures a portion of its projected fuel needs through the long-term RFP process and as needed will procure competitively priced natural gas supply through informal market solicitations based on the specific business opportunities and need. Binding commitments for long-term gas supply need to conform to this process and Duke Energy's Commodity Risk Policy, Credit Policy, Delegation of Authority and Approval of Business Transactions Policy.

Environmental Considerations

DEF places a strong emphasis on environmental quality in its planning process. While two resource alternatives may be economically competitive, their effects on the environment may be quite different, and DEF prefers not only the least cost resource but also one that satisfies DEF concerns for the quality of the environment. Accordingly, the technology and fuel type for a preferred generation alternative should be a relatively clean source. It must not only comply with current Clean Air Act and other environmental provisions, but must also provide substantial flexibility in the event of changes in environmental rules. Additionally, the generation technology should have a high efficiency (low heat rate). Efficient plants use less fuel per unit of electric service delivered and therefore create smaller environmental impacts per unit of service. Combined with the use of a clean combustion technology, efficient plants reduce the exposure of DEF to new environmental rules, constraints, or environmentally related taxes.

The Citrus CC will have a low environmental impact under all standard operating conditions. Combined cycle power plants operating on natural gas are one of the cleanest sources of fossil fuel power generation. Natural gas is a low sulfur, low nitrogen oxide, low particulate emission power plant fuel. Nitrogen oxide emissions will further be controlled by a selective catalytic reduction system located in the HRSGs. The Citrus CC will burn a relatively clean fuel and have a low environmental impact.

As a natural gas fired combined cycle power plant, the Citrus CC will be designed to comply with all current environmental regulations including anticipated additional regulations being proposed under the Clean Air Act. In addition to being low in sulfur, air toxics, and nitrogen oxide emissions, combined cycle natural gas plants produce approximately half of the CO2 emissions of a similarly sized conventional coal plant. The Citrus CC is designed to comply with the anticipated requirements of the New Source Performance Standards for Greenhouse Gas

Emissions. In addition, combined cycle facilities have a much lower thermal discharge impact compared to conventional steam generation and produce negligible streams of solid waste.

DEF's assessment of the Citrus CC 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 Citrus CC project will use the existing CR3 intake structure and a new discharge structure in the existing discharge canal.

The table below lists the required environmental permits for the Citrus CC along with the anticipated permitting schedule.

Item	Not Required	Required	To Be Applied For (Date)	Expected Receipt (Date)
Water Discharge to Surface Waters (NPDES) Permit		X	Jun-2014	Nov-2015
404 Permit / 401 Water Quality Certification		X	Jun-2014	Nov-2015
Domestic Wastewater		X(1)	Jun-2014	Oct-2015
Industrial Wastewater (non-NPDES)		X(1)	Jun-2014	Oct-2015
Water Use		X(1)	Jun-2014	Oct-2015
Water Use Area Restrictions (e.g. SWUCA, MIA) Applicability	X			
Corps of Engineers Permit(s): wetlands / aerial crossings		X	Jun-2014	Nov-2015
Environmental Resource Permit (ERP) for Wetlands		X(1)	Jun-2014	Nov-2015
ERP: Surface Water Management (MSSW)		X(1)	Jun-2014	Nov-2015
Solid Waste Disposal Permit	X			
Ash Disposal Permit	X			
Hazardous Waste Disposal Permit	X			
PSD (Air Construction) Permit		X(2)	Jun-2014	Nov-2015
Federal Aviation Administration License		X(3)	Sep-2016	Dec-2016
Certificate of Need		X(1)	Jun-2014	Dec-2017
Local Construction Permit		X(1)	Jun-2014	Dec-2015
Local Zoning Approval (Conditional Use Permit)		X	Mar-2014	Sep-2014
Spill Prevention Control Measures Permit		X	Aug-2016	Dec-2016
Section 10 (Wildlife) Permits	X			
Migratory Bird	X			
Department of Transportation		X(1)	Jun-2014	Oct-2015
Air: Title V Operating Permit		X	Jun-2014	Nov-2015
Electric and Magnetic Field (EMF) requirements: FDEP		X(1)	Jun-2014	Oct-2015
Title IV (Acid Rain) Permit		X(1)	Jun-2014	Nov-2015
Site Certification Application (includes state, local permitting and authorizations) or Supplemental SCA if existing site		X	Jun-2014	Oct-2015
Holcim Environmental Resource Permit (ERP) Modification		X	Jun-2014	Sep-2014
Holcim Department of Army Permit Modification		X	Jun-2014	Sep-2014
(1) Items will be addressed through the Site Certification Application (SCA)				
(2) Item will be coordinated with SCA				
(3) May be required for construction cranes				

j. Transmission requirements.

The Citrus CC siting review identified the Citrus County location as a favorable location from a transmission perspective both because of the availability of significant transmission resource in the area related to the CREC and because the construction of the Citrus CC would mitigate potential transmission upgrade needs triggered by the retirement of Crystal River Units 1, 2, and 3.

There are substantial Company transmission substation facilities, lines, and other structures and facilities in Citrus County and the surrounding area to transmit the generation at the CREC from the CREC across DEF's system to DEF's customers. At the beginning of 2013, there were over 3,000 MW of summer generation capacity from the Company's nuclear and coal-fired generation plants located at the CREC. All of this generation was supported by DEF transmission facilities, structures, and lines in the vicinity of the CREC.

In February 2013, the Company decided to retire CR3, its nuclear power plant, located at the CREC. CR3 alone accounted for almost 800 MW of the CREC's summer generation capacity. In addition, the Company's oldest coal-fired generation plants, its Crystal River Unit 1 ("CR1") and Unit 2 ("CR2") plants, cannot comply with the EPA MATS regulations in their current configuration and as they are currently operated, and face eventual retirement due to the EPA CAVR. As a result, the Company faced potential, additional generation plant retirements at the CREC in the immediate future. The existing and potential retirements of substantial CREC generation capacity freed up some of the existing transmission capacity that was built to support the CREC generation capacity. This existing transmission capacity was available to support new generation in Citrus County or the surrounding area.

The only transmission work that is necessary for the Citrus CC is the switchyard and transmission bus line work to actually connect that plant with the existing DEF transmission facilities that are already connected to DEF's transmission system and the electric power grid in Florida. One 820 MW block of the 1,640 MW Citrus CC will be connected to the existing 500 kV transmission system located at the CREC effectively replacing the generation from the retired

CR3 unit. The other 820 MW block will be connected to the existing CREC 230 kV transmission system effectively replacing the CR1 and CR2 generation when it is retired.

The transmission lines will use existing Duke Energy Florida rights-of-way.

Substation and Transmission design will have a multi-breaker substation configuration that will provide a reliable interconnection. Plant design will include allocations for interconnection at 500kV and 230kV and all transmission equipment installed will meet Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC") and DEF System Transmission Reliability Standards.

5. Resource Need and Identification.

a. Reserve Margin and Loss of Load Probability.

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. 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.

Projected DEF Reserve Margins With and Without Citrus CC

		With Citrus CC		Without Citrus CC	
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%	11,012	20.4%
2017	9,307	11,232	20.7%	11,232	20.7%
2018	9,439	11,362	20.4%	10,542	11.7%
2019	9,813	12,132	23.6%	10,492	6.9%
2020	9,935	12,027	21.1%	10,387	4.5%

DEF's needs in the period are driven not only by summer load growth (although growth in this period is projected at 1.8% per year due in part to expansion of wholesale contracts), but primarily due to recent and upcoming unit retirements. In addition to the 2013 retirement of CR3 (790 summer MW, DEF share), CR 1and CR2 will retire due to environmental restrictions (740 summer MW).

These capacity reductions and the additional peak demand translates into a capacity need of 840 MWs in year 2018, 1338 MW in 2019; and 1590 MW in 2020 as can be seen in the table above.

The Reserve Margin by 2018 is 20.4%. Without the addition of the Citrus CC in 2018, and the addition of the Suwannee CTs and the Hines Chillers prior to 2018, the Reserve Margin would have fallen below the minimum 20% requirement. The Suwannee CTs contribute 320 MWs and the Hines Chillers 220 MW.

b. Resource Planning Process.

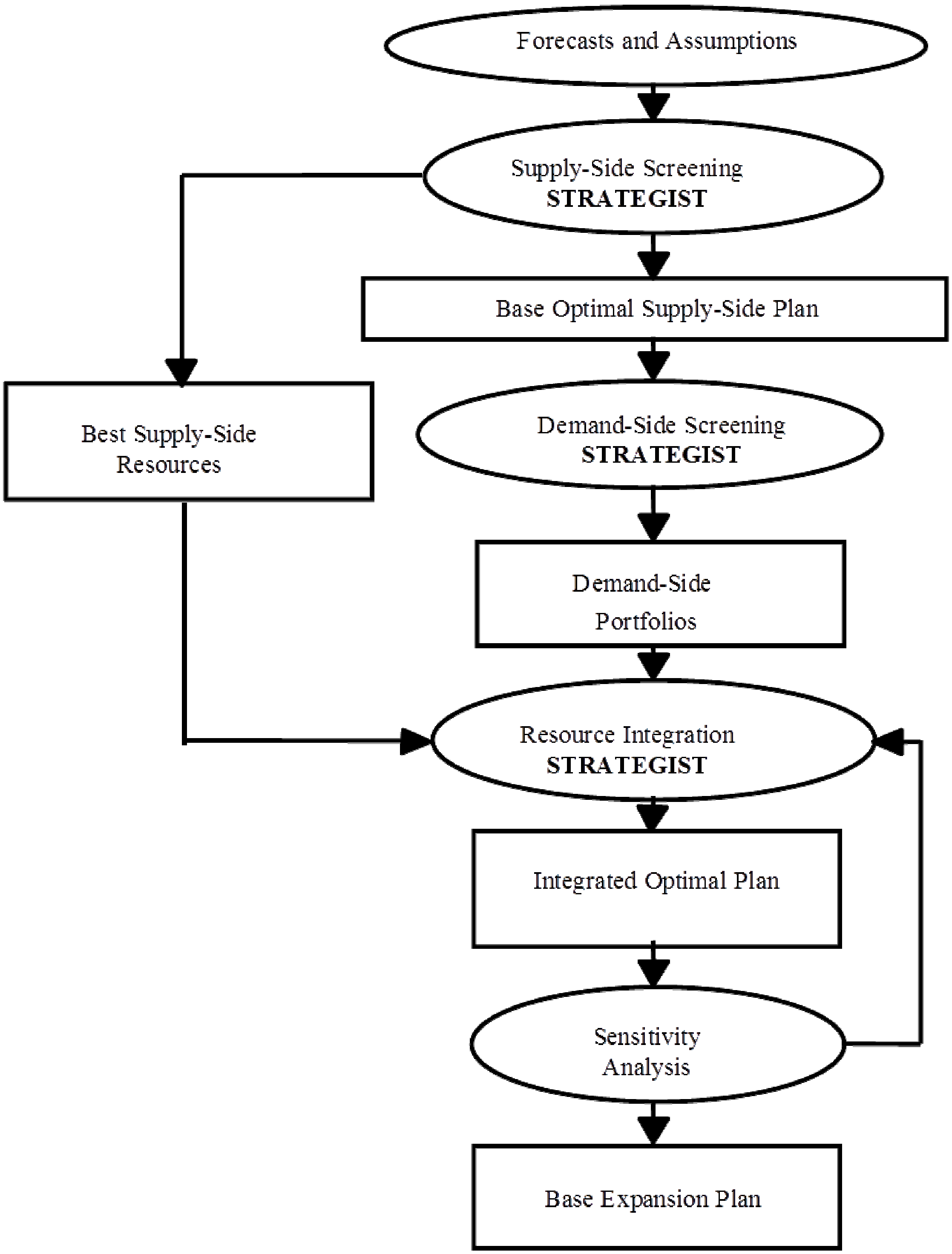
DEF employs an Integrated Resource Planning ("IRP") process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models to evaluate a wide range 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



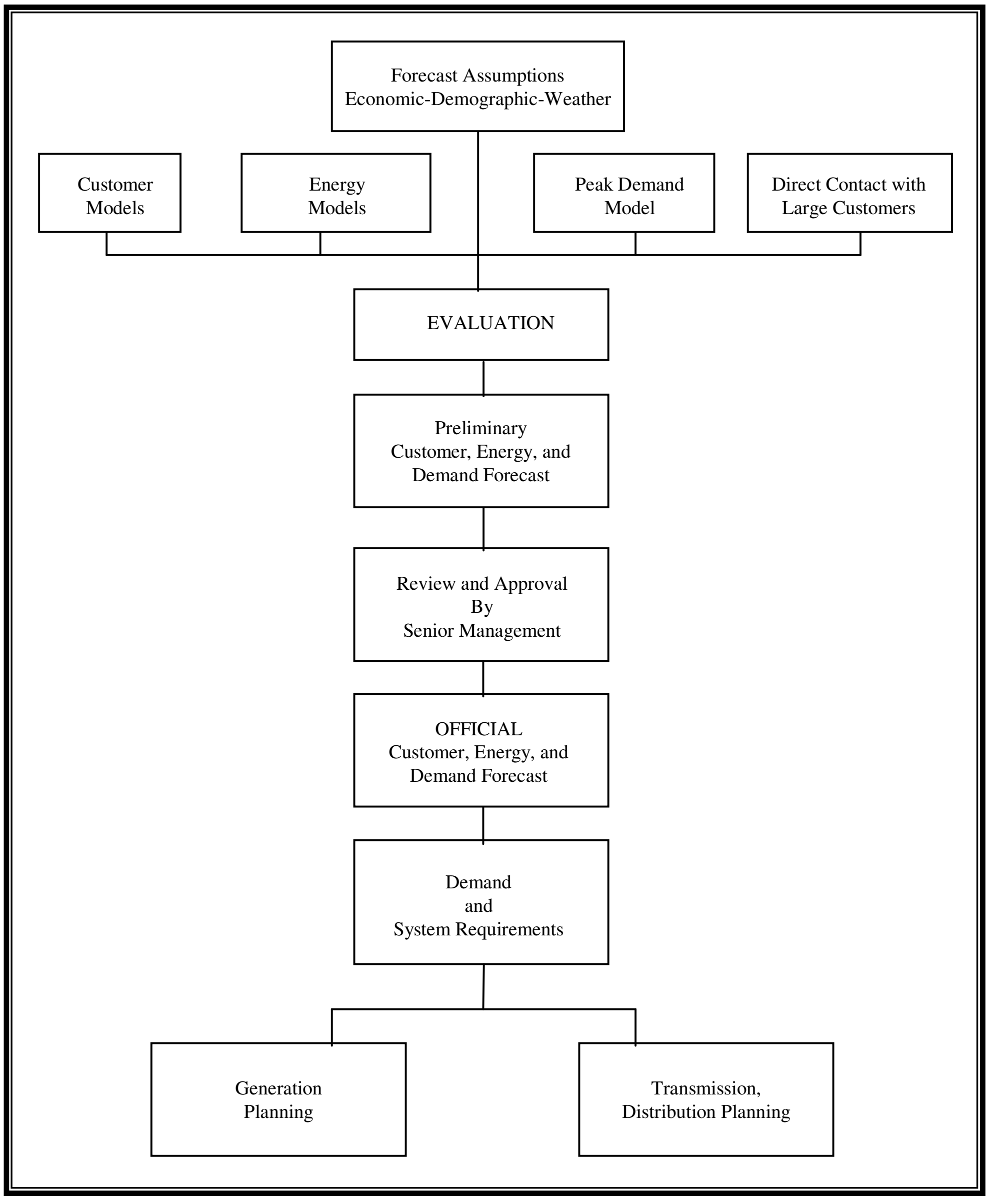
c. Forecasting methods and procedures.

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.

FIGURE 2.1

Customer, Energy, and Demand Forecast



d. 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.

e. 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) are used. 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.

f. 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.

g. 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 statistically adjusted end-use (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.

h. 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 EIA, along with trended projections of both by Itron, capture a significant piece of the changing future environment for electric energy consumption.

i. 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.

j. 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 . 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.

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.

The result of this process, including identified trends in customer growth, usage, net energy for load and winter and summer peak demands, making allowance for projected conservation efforts results in the final load forecast shown here and in Schedules 2.1, 2.2, 2.3, 3.1, 3.2, 3.3, and 4 of DEF's 2014 Ten Year Site Plan.

	LOAD FORECAST		
	Firm 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
2018	9,544	9,439	41,995
2019	9,639	9,813	43,013
2020	9,971	9,935	43,998
2021	10,059	9,952	44,419
2022	10,144	10,067	44,870
2023	10,225	10,173	45,459

k. Other Planning Assumptions.

1. Fundamental Forecast.

All of DEF's 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 over a period between 3 and 5 years in the future.

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 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.

The Fundamental Forecast is released each spring with an updated forecast typically in the fall of the year. 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.

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 results in the calculation of the low and high natural

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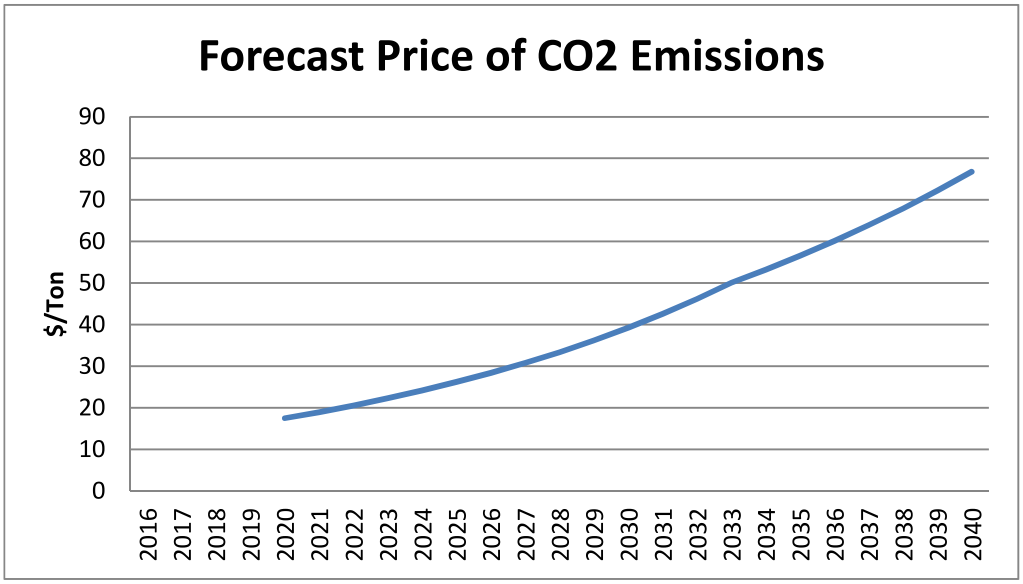
gas price forecasts around the Fundamental Natural Gas Forecast. Based on these calculations, the low natural gas forecast is 18 percent lower and the high natural gas forecast is 14 percent higher than the Duke Energy Fundamental Natural Gas Forecast, as shown in the table below. Duke Energy's methodology 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.

[redacted]

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. Although current legislative efforts to enact a policy that places a national price on carbon remain highly uncertain, it is still a possibility. 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.



Duke Energy also typically evaluates a scenario in which there is no monetized cost for carbon emissions and did so in the RFP evaluation.

2. Economic and Financial Assumptions.

Economic and Financial Assumptions

DEF's evaluation of its supply-side generation alternatives takes into account those economic and financial factors that affect the determination of the most economic generation expansion plan. DEF prepares and incorporates forecasts for key economic and financial factors such as the general inflation rate, construction cost escalation rate, and interest rates into its analysis of generation alternatives. These forecasts are based on DEF's annual assessment of regional and national economic factors and represent what DEF anticipates in support of its financial management process.

The values used in assessing alternatives in the selection of the Citrus CC are shown in the table below.

Financial Assumptions Base Case

AFUDC RATE		6.46	%
CAPITALIZATION RATIOS:			
	DEBT	50	%
	PREFERRED	0	%
	EQUITY	50	%
RATE OF RETURN			
	DEBT	3.75	%
	PREFERRED	0	%
	EQUITY	10.5	%
INCOME TAX RATE:			
	STATE	5.5	%
	FEDERAL	35	%
	EFFECTIVE	35.26	%
OTHER TAX RATE:		N/A	%
DISCOUNT RATE:		6.46	%

6. Future Demand-Side Management.

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. These programs contribute savings both in Energy Management and through conservation.

DEF projects the following annual savings through its DSM programs over the next ten years.

	Summer MW	Winter MW	

	Conservation	Energy Management	Conservation	Energy Management	Energy GWh
2014	37	-63	66	38	70
2015	31	11	58	29	60
2016	28	8	49	16	56
2017	25	41	47	34	49
2018	22	17	36	23	45
2019	21	56	34	58	43
2020	22	31	40	36	46
2021	20	10	34	15	43
2022	19	9	32	14	40
2023	18	9	31	14	39

DEF proposed new conservation goals for the ten year period from 2015 through 2024 in a filing with the Commission as part of Docket No. 130200-EI. Over the next five years (2015-2019) the proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. The proposed conservation goals will lead to an increase in DEF's firm winter and summer peak demand. Therefore, if adopted by the Commission, DEF's proposed DSM goals further establish the need for the Citrus CC.

7. Supply Side Alternative Screening.

DEF includes conventional and renewable energy resources as potential capacity addition alternatives in its overall Resource Planning process. These resource alternatives are periodically reassessed and the performance characteristics updated to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, performance, and cost.

First, DEF examined the commercial availability of each technology for use in utility-scale applications. For a particular technology to be considered commercially available, the technology must be able to be built and operated on an appropriate commercial scale in continuous service by or for an electric utility. Reasonable levels of detail for emerging technologies were developed to allow DEF to screen the technology options and to stay abreast of potential economic benefits as they mature.

Second, technical feasibility for commercially available technologies was considered to determine if the technology met DEF's particular generation requirements and that it would integrate well into DEF's system. Evaluation of technical feasibility included the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on DEF's system (e.g., baseload, intermediate, cycling, or peaking).

Finally, for each alternative, an estimate of the levelized cost of energy production, or "busbar" cost, accounting for capital, fuel, and O&M costs over the typical life expectancy of the unit, was developed. Busbar costs allow for comparison of fixed and operating costs of all technologies over different operating levels. The comparison considers the long-term economics of future power plants at varying levels of capacity factor. Data used to assess each technology includes fixed and variable O&M, fuel, construction costs, and the levelized fixed charge rate.

For the screening of alternatives, the data are generic in nature and thus not site specific. The costs and operating parameters are adjusted to reflect installation in the southeastern United States. The operating characteristics are based on state-of-the-art designs, and for most technologies, the performance and costs are based on a specific size unit. The cost and performance projections were made with Burns and McDonnell assistance and internal DEF resources.

Categories of capacity addition alternatives that were reviewed as potential resource options for in-service dates through 2018 included *conventional* technologies that utilize non-renewable resources and *alternative* technologies that utilize renewable sources of energy. In the most recent assessment, the following generation technologies were screened:

Conventional Technologies
Combustion Turbine (CT)
Combined Cycle (CC)

Alternative Technologies
Solar Photovoltaic (PV)
Wood (commercial)

These are mature, proven technologies.

Wind projects have high fixed costs but essentially no operating costs. Therefore, at high enough capacity factors they could become economically competitive with the lower-cost technologies identified. However, the geographic and atmospheric characteristics of Florida limit the ability of wind projects to achieve those capacity factors. Wind projects must be constructed in areas with high average wind speed. In general, wind resources in Florida, and throughout the southeast, are limited. The average wind speed in Florida is below 14 miles per hour and is not sufficient to be an economic alternative. Because a wind project would not be expected to operate above a 20-25 percent capacity factor in the Florida geographic area, it is not a viable alternative to the CC for intermediate duty. Further, because wind is not dispatchable, it is not a suitable alternative to the CT for peaking duty. As a result, wind was eliminated from consideration as a potential resource to meet future generation needs.

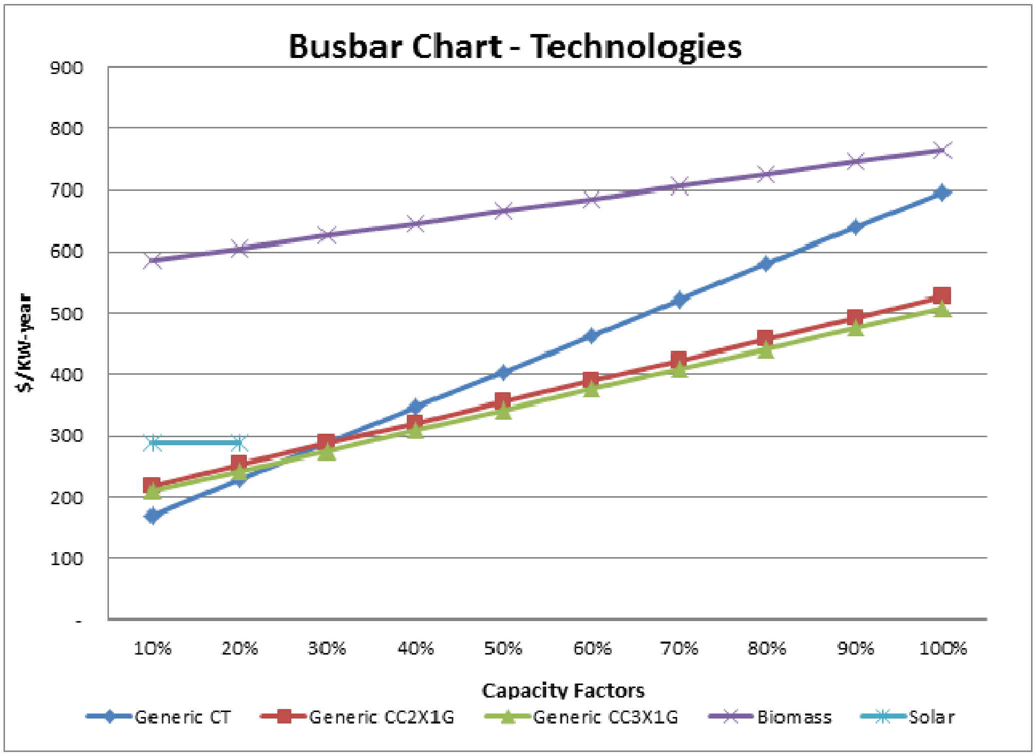
Solar photovoltaic (PV) projects are also technically constrained from achieving high capacity factors. In Florida they would be expected to operate at approximately 20 percent capacity factor making them unsuitable for intermediate or higher duty cycles. At the lower capacity factors, they, like wind, are not dispatchable and therefore not technically suited to provide reliable peaking capacity. In this evaluation, recognizing that the need for new generation was driven in large measure by the retirement of existing baseload units (Crystal River Units 1, 2, and 3), DEF recognized a system need for dispatchable, high capacity factor generation. Solar projects do not provide dependable dispatchable capacity and have not yet demonstrated economic competitiveness as an energy only resource. Similarly, biomass generation on a utility scale was eliminated because of high busbar costs, as well as potential environmental emission challenges.

Moderately high capital costs, as well as high operating cost, eliminated advanced nuclear technologies in the screening process. Long lead times led DEF to further forego nuclear as a viable means of satisfying its capacity needs during this planning period.

With solar photovoltaic and biomass technologies eliminated from further consideration, only three technologies were retained for the more detailed economic analysis phase of the evaluation. They included one simple cycle combustion turbine option and two combined cycle options.

The table below and the accompanying figure provide the busbar cost comparison of the four technologies identified as commercially available, technically feasible, and potentially cost-effective, making them viable generation alternatives in Florida. This graph illustrates that the combustion turbine (CT) is the most economical generation alternative for peaking duty cycles, and the combined cycle (CC) is the preference for intermediate and base load operation. Combustion turbines and combined cycles also have the lowest overnight capital costs.

Alternative	Summer Total Capacity	Overnight Generation Capital Costs 2016$		Overnight Transmission Capital Costs 2016$		O&M Costs 2016$ Fixed	O&M Costs 2016$ Variable	Summer Heat Rate	Equivalent FOR	Fuel Type
	(MW)	$/Kw	$M	$/Kw	$M	$/Kw	$/Mwh	Btu/Kwh	(%)	
Combustion Turbine	186.66	457	85	142	27	72	10.89	10,343	2.05%	Gas / Oil
Combined Cycle 2x1 G	792.97	904	717	392	311	72	5.72	6,800	6.36%	Gas / Oil
Combined Cycle 3x1 G	1,189.10	870	1,035	349	414	70	4.83	6,820	6.36%	Gas / Oil
Biomass	50.00	4,588	229	124	6	111	5.75	13,000		Wood
Solar Photovoltaic	25.00	1,956	49	124	3	89	-	-		Solar



DEF has historically considered both coal fired and nuclear generation. While neither of these is represented in the data above, DEF continues to monitor developments affecting cost and feasibility in both technologies.

New coal fired generation currently faces significant cost and feasibility challenges due to increasing environmental regulation. EPA's New Source Performance Standards for Control of Greenhouse Gas Emissions place stringent limits on the emission of CO_2 from coal fired plants and may require the use of carbon capture and sequestration (CCS). CCS is an emerging technology, not yet in full utility scale service in the United States. The examples of early integration of this technology have faced significant cost and operational challenges. In addition, successful implementation of CCS requires geology conducive to permanent sequestration of the CO_2. Adequate geology in Florida has not been demonstrated.

New nuclear generation also continues to face significant challenges from both licensing and cost pressures. DEF has for several years been pursuing development of a nuclear plant at DEF's site in Levy County. In the planning for the 2018 Need, DEF recognized that the development timeline for a nuclear facility including both licensing and construction, even with the investment made to date in the Levy Project, would not meet the in service needs for this time period.

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.

8. Resource Integration

Once the range of supply-side and demand-side alternatives has been screened, an integration assessment is conducted to determine the optimum supply-side expansion plan, given the portfolio of cost-effective DSM programs identified, as previously described. In this phase, DEF screens expansion plan alternatives comprised of the viable generation technologies using the Strategist resource optimization model. The results of the economic screening in Strategist showed the combined cycle and combustion turbine generation technologies were consistently selected in the top ranked plans. The top plans include the same resource additions through the ten-year planning horizon. The top ranked plan includes the addition of two combustion turbines at the Suwannee River Plant in 2016, addition of inlet chilling to supply additional summer capacity from the combined cycle units at the Hines Energy Center by 2017, the Citrus CC in 2018 and the addition of an undesignated future combined cycle unit in 2021. This plan was chosen by DEF as the Integrated Optimal Plan and was also published as the Base Expansion Plan in the Company's 2014 TYSP filed with the FPSC on April 1, 2014 as shown in the table below.

DEF considered the option of increased DSM as an alternative to allow deferral of the Citrus CC. Because of the large size of the need for capacity in the 2018 timeframe, it was recognized that

DSM programs of such a scale necessary to defer this large block of capacity could not be developed, approved and implemented in the necessary timeframe. In addition, DEF has screened the current DSM programs, identified as the most cost effective programs available, against a generic CC unit in the timeframe of the Citrus CC and found that no cost effective DSM programs were available to defer the Citrus CC.

9. Resource Selection: 2018 RFP.

DEF Request For Proposal ("RFP"or the "DEF 2018 RFP") General Description:

Prior to filing its petition for determination of need for the Citrus CC pursuant to Section 403.519, Florida Statutes, DEF issued the DEF 2018 RFP to evaluated supply-side alternatives to the Citrus CC as its Next Planned Generating Unit ("NPGU"). DEF developed the 2018 RFP consistent with Rule 25-22.082 of the Florida Administrative Code ("Bid Rule") and complied with the Bid Rule in the 2018 RFP process and evaluation.

The DEF 2018 RFP included three key components: the Solicitation Document, the Bidder Response Package, and the Bidder Response Schedules and Forms. Attachments to the 2018 RFP included DEF's key Terms and Conditions and DEF's 2013 TYSP.

The DEF 2018 RFP Solicitation Document was divided into five parts. Part I was an introduction of the 2018 RFP, the objectives of the 2018 RFP, DEF's 2018 resource needs, the 2018 RFP schedule, and the 2018 RFP Official Contact. Part II provided potential bidders the instructions for responding to the 2018 RFP Solicitation Document and described the information and responsibilities for the potential bidders. Part III described the 2018 RFP evaluation process. Part IV described the Company's NPGU. Part V provided DEF's system specific conditions, which was information about DEF's system that was important for potential bidders to respond to the 2018 RFP. A copy of the 2018 RFP Solicitation Document and all attachments, including the Bidder Response Package and Bidder Response Schedules and Forms in included as an appendix to this Need Study.

The purpose of the DEF 2018 RFP was to solicit competitive proposals for supply-side alternatives to the Company's NPGU, the Citrus CC. The Citrus CC is approximately 1,640

MW (summer rating) with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. Accordingly, DEF sought a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018. DEF invited offers for all resource types as long as they were from a dispatchable, supply-side resource and considered to be firm capacity with firm deliverability into DEF's system. DEF allowed bidders to propose both existing and new capacity, and tolling and purchase power arrangements, including system power sales. Potential bidders were allowed up to two variations (such as power augmentation, operating reliability impacts or financing terms) in project term and/or pricing at no additional cost in their proposals. DEF requested creative responses which employed innovative or inventive technologies or processes. DEF sought resources that offered the maximum value, based on price and non-price attributes, to the Company's customers.

DEF specifically explained in its System Specific Conditions in the 2018 RFP Solicitation Document that the preferred Bulk Electric System ("BES") location for new DEF generation capacity was is in Citrus County. DEF explained that the Citrus County location was preferred because the new capacity was replacing generation that was being retired in the area. DEF even explained that this location or other areas in proximity to Citrus County provided transmission reliability benefits for DEF as well as neighboring transmission systems within the Florida Region. Finally, DEF explained that if the new generation capacity was not located in the vicinity of Citrus County, DEF expected significant Transmission Network Upgrades would be needed on DEF's transmission system as well as neighboring transmission systems within the Florida Region. In other words, DEF explained that if the bidders located their proposed generation in Citrus County they would take advantage of the available transmission capacity that was available on the BES due to DEF's generation retirements in the area.

DEF 2018 RFP Pre-Issuance and 2018 RFP Issuance.

On September 24, 2013, DEF notified potential bidders about the issuance of the DEF 2018 RFP by publishing public notices in major newspapers, periodicals and trade publications with statewide and national circulation including Megawatt Daily, SNL, the Tampa Tribune, the Orlando Sentinel, Energy Biz, and Power Engineering. The Company set up a 2018 RFP website that was publicly available the same day and that contained the information in the public notice. The public notice provided a general description of the Company's NPGU, the name and address of the contact person from whom an RFP package could be requested, the Company's website address at which an RFP package could be obtained, and the schedule of critical dates for the RFP process. A press release was also published that contained the same information in the public notice and that contained the 2018 RFP website address and link. The Company's press release about the 2018 RFP was referred to in articles by a number of news services, both in print and on-line, including the Tampa Bay Times, the Wall Street Journal, the Citrus County Chronicle, Yahoo Finance, and various industry trade journals.

Also on September 24, 2013, DEF issued a pre-release version of the RFP. The pre-release RFP documents were made available on the 2018 RFP website for dowloading. The pre-release RFP documents were also available to registrants on Power Advocate, a web-based RFP interface tool that DEF used for the 2018 RFP. DEF provided instructions for registration on Power Advocate and 33 individuals with 27 companies registered on Power Advocate. A copy of the 2018 RFP was also provided to the Florida Office of Public Counsel and filed with the Commission.

DEF held a public 2018 RFP pre-Issuance meeting on October 2, 2013 to review the information in the pre-release RFP documents and to receive feedback on the RFP. Over 20 people attended the pre-Issuance meeting in person in Tampa, Florida or via a conference call line or the live web presentation set up for the pre-Issuance meeting. DEF made a presentation at the meeting regarding the RFP objectives, the types of resource alternatives DEF sought in the RFP, the 2018 RFP documents, the RFP process, and other requirements of bidders. Potential bidder questions about the RFP documents and process were invited and any answers to questions were provided and posted on the 2018 RFP website.

The DEF 2018 RFP was officially released on October 8, 2013. DEF held a Bidders Conference for all potential bidders on October 18, 2013. The purpose of the Bidders Conference was to allow interested parties the opportunity to ask questions and seek additional information or clarification about the RFP solicitation process. DEF made another presentation at the bidders meeting regarding the RFP objectives, the types of resource alternatives DEF sought in response to the RFP, the 2018 RFP documents, the RFP process, and other bidder requirements. Over 12 people attended the Bidders Conference in person in Tampa, Florida or via a conference call line or the live web presentation set up for the meeting. Potential bidder questions about the RFP documents and process were invited and any answers to questions were provided and posted on the 2018 RFP website. DEF also notified the Office of Public Counsel and the Commission Staff of the 2018 RFP pre-Issuance meeting and Bidders Conference.

No potential participants filed objections to the 2018 RFP documents with the Commission within 10 days of the issuance of the 2018 RFP. DEF provided potential bidders 60 days to respond to the 2018 RFP between the issuance of the 2018 RFP on October 8, 2013 and the due date for proposals on December 9, 2013.

DEF also employed Alan Taylor with Sedway Consulting, Inc. as an Independent Monitor and Independent Evaluator for the 2018 RFP. Mr. Taylor assisted the Company with the development of the 2018 RFP documents and associated website, reviewed DEF's solicitation process, and performed a parallel and independent economic evaluation of DEF's NPGU and the proposals DEF received in response to the 2018 RFP. His contact information was provided to potential bidders in the RFP Solicitation Document and on the 2018 RFP webiste. Potential bidders were asked in the 2018 RFP Solicitation Document and solicitation process to contact Mr. Taylor and the Company's contact with any questions or comments regarding the 2018 RFP. Mr. Taylor's role as an Independent Monitor was to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP documents were clear, fair, and consistent with the Bid Rule. Mr. Taylor determined that the 2018 RFP documents were reasonable and that the 2018 RFP solicitation process was fair to all participants.

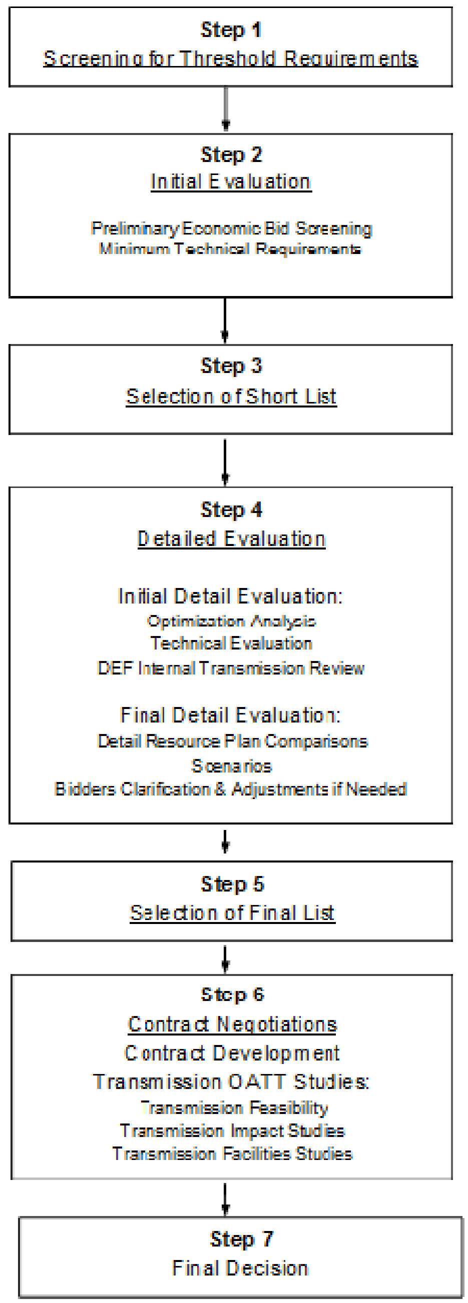
DEF 2018 RFP Proposals:

On December 9, 2013, in addition to the self-build proposal, DEF received 6 alternative Bidder proposals with an additional 5 variations on proposals for a total of 12 proposals (including the self-build proposal) in response to the 2018 RFP. A total of 1,332 MW of alternative capacity resources were proposed in response to the Company's 1,640 MW reliability need in 2018. Of the 1,332 MW of alternative capacity proposals, two were located within DEF's control area and the remaining proposals were located outside DEF's service area. Proposals outside DEF's transmission area required additional transmission studies by the host transmission providers. All but one of the alternative proposals were from existing sites. All but one of the alternative proposals relied on natural gas as the fuel for the proposed resource. The alternative capacity proposals varied in MW capacity and proposal contract term lengths; none of the alternative proposals equaled the 35-year life of the Citrus County CC NPGU. Even if all alternative proposals were combined together, DEF was still required to build generation in 2018/19 to meet its reliability need and to build generation again after the alternative proposal terms expired. A confidential summary of the proposals is included in Appendix D to this Need Study.

DEF 2018 RFP Evaluation Process:

DEF utilized a seven-step evaluation and screening process to review proposals to the 2018 RFP and to select the best alternative on price and non-price attributes for DEF's customers. Figure III-1 illustrates the evaluation process, starting with the receipt of proposals to the final decision. DEF's evaluation of the proposals to the 2018 RFP consistent with this process is described more fully below.

FIGURE III-1
Evaluation Process



Step 1: Screening for Threshold Requirements.

Subsequent to the receipt of the Bidders' proposals, DEF thoroughly reviewed and assessed each proposal to ensure that it met the Threshold Requirements listed in the RFP. Threshold Requirements represent the minimum requirements that all proposals are required to meet. Bidders were required to include sufficient documentation in their proposals to demonstrate that they met all Threshold Requirements. Failure to conform to the Threshold Requirements was grounds for disqualification. The Bidder Threshold Requirements are listed in FIGURE III-2.

FIGURE III-2
Threshold Requirements

A. General Requirements

- The proposal is received on time.
- The proposal submittal fee is received by DEF.
- The pricing schedules are properly specified and the proper price indices are used.
- Power must be available for delivery under the contract May 1, 2018
- The proposed contract end date is no earlier than April 30, 2033

B. Operating Performance Thresholds

- If the project is located in DEF's system, the Bidder's proposal will be required to show documentation that the following operational criteria can be meet:
  - to operate the project to conform with DEF's ***Voltage Control*** requirements.
  - to operate the project to conform with DEF's ***Frequency Control*** requirements.
  - to be ***Fully Dispatchable*** and install ***Automatic Generator Control*** ("AGC") that is tied into DEF's Energy Control Center **[New and Existing Unit Proposals]**.
- If the project is located outside of DEF's system, New and Existing Unit Proposals must provide documentation to show that the proposal is ***Fully Dispatchable*** and provide ***Dynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.
- The Bidder must show documentation they are willing to ***coordinate the project's maintenance scheduling*** with DEF.
- System Power Proposals must show documentation that the proposal is ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). System Power Proposals must also provide D***ynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.

C. Terms & Conditions Thresholds

- Bidders must agree to each of the Terms & Conditions identified in Attachment A.
  - OR -
- If Bidder has any objections to the Terms & Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

D. Site Control Thresholds [New and Existing Unit Proposals]

- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title (or long term lease) and legal description of the property is required for **Existing Unit Proposals**.

E. Transmission Threshold

- If the proposal is for resources located outside of DEF's system, the Bidder must provide a transmission plan that exclusively utilizes firm transmission service from the host system to the DEF system. Bidders must provide evidence that the host system is willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals. Bidders must provide host utility documentation that the results of a generator feasibility study and/or a host transmission system impact study performed by the host system will be completed or documentation such as a transmission study agreement showing that the results will be available no later than 30 days following the bid submittal date.
- For New Unit Proposals physically located inside the DEF system, documentation that the required Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT has been submitted to DEF **[New Unit Proposals]**.
- The Transmission Information Schedule (Schedule 7 of the Response Package) is properly completed for **All Proposals**.

Threshold Requirements Screening Results:

None of the Bidder proposals initially passed the Threshold Requirements screen without any deficiencies. All proposals required clarifying questions to obtain additional information to assist DEF in determining if the proposals met the Threshold Requirements. DEF sent clarifying questions to the bidders on December 26, 2013. All bidders responded to the clarifying questions. Four bidder proposals required additional threshold transmission information about the status of their host utility transmission study and about their ability to obtain a host transmission agreement within the required timeframe. All of these bidders responded with a willingness to pursue the required transmission information, but they all had issues with obtaining the transmission information by required date. Because these bidders proposed to supply DEF with capacity from existing units DEF knew their host transmission utility and had a working relationship with and some knowledge about the host utility. As a result of this information, and because DEF had received a limited number of proposals in response to the 2018 RFP, DEF elected to continue with the next steps in the RFP process and to evaluate these deficiencies later in the qualitative assessment of the proposals after completion of the quantitative evaluation of the proposals, if a qualitative assessment was necessary. DEF, accordingly, did not disqualify these bidder proposals for failure to meet the 2018 RFP Threshhold Requirements.

Another bidder proposal failed to satisfy the Operating Performance and Site Control Threshold Requirements. DEF sent clarifying questions, again on December 26, 2013, and the bidder supplied additional information regarding the Operating and Site Control Threshold Requirements for the bidder's proposal. The additional information included an expressed willingness to pursue operating delivery alternatives to the Operating Performance Threshold Requirements, however, the information supplied did not meet this Threshold Requirements. Again, because DEF had received a limited number of proposals in response to the 2018 RFP, DEF elected to continue with the next steps in the RFP process and to evaluate these deficiencies later in the qualitative assessment of the proposal after completion of the quantitative evaluation of the proposals, if a qualitative assessment was necessary. DEF, accordingly, did not disqualify this bidder proposal for failure to meet the 2018 RFP Threshhold Requirements.

DEF discussed its approach to the Threshold Requirements deficiencies in some of the bidder proposals with Mr. Taylor and Mr. Taylor agreed with the Company's approach. Mr. Taylor agreed that DEF's decision to defer the assessment of these Threshold Requirements deficiencies to the qualitative evaluation of the proposals, if a qualitative assessment was required after the economic evaluation of the proposals, was a fair approach to the evaluation of the proposals even though DEF had the right under the 2018 RFP to disqualify the non-conforming proposals from further evaluation in the RFP evaluation process.

The following Table summarizes that DEF checked all Threshold Requirements for all bidder proposals. As explained above, despite Threshold Requirement deficiencies with some bidder proposals, DEF elected to continue with the economic evaluation of the proposals. All Threshold Requirements deficiencies would be evaluated in the qualitative evaluation of the proposals if a qualitative assessment was necessary after DEF completed the economic evaluation of the proposals.

Final "Over All" Threshold Requirements Review

Proposal #	A	B	C	D	E	F
Accepetd (√) Rejected (X)	√	√	√	√	√	√

Threshold Requirement - Proposal Reviews By Sections

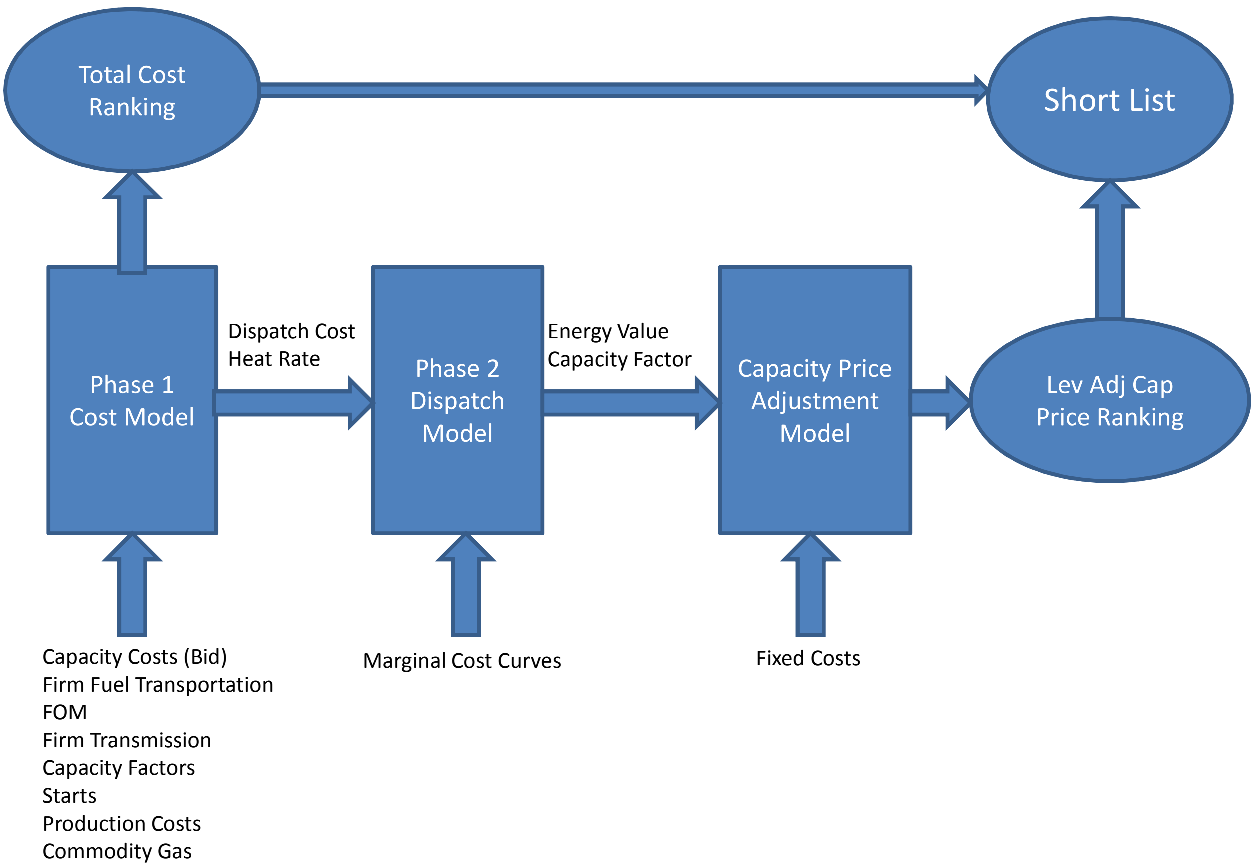
Proposal #	A	B	C	D	E	F	Threshold Requirement Review Sections
Accepetd (√) Rejected (X)	√	√	√	√	√	√	A. General Requirements
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	B. Operating Performance Thresholds
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	C. Terms & Conditions Thresholds
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	D. Site Control Thresholds [New and Existing Unit Proposals]
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	E. Transmission Threshold

Note: Although various concerns were identified by Review Leads and addressed in DEF 12/26/13 Clarifyng Questions, bidders responses to the 12/26/13 Clarifying Questions were adequate for continued evaluation and review beyond Step 1 - Threshold Requirements

Step 2: Initial Evaluations

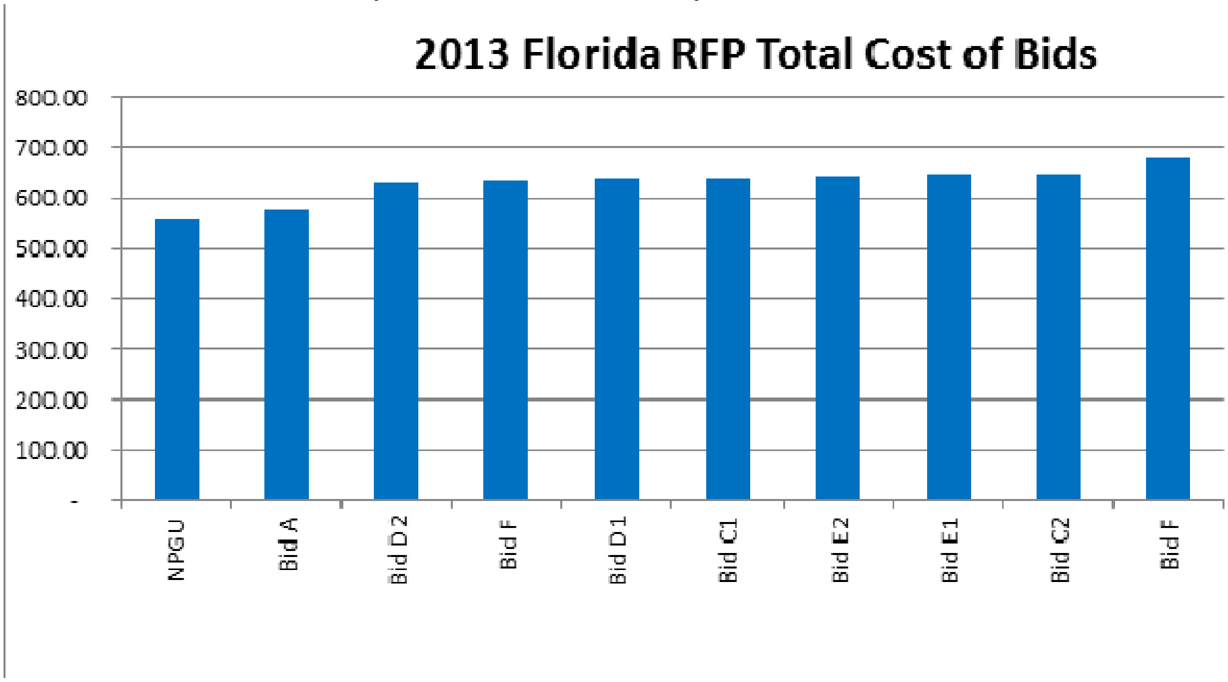
Initial Economic Screening

The initial economic screen was performed in two phases, one in which the operational cost of each bid was evaluated on a standalone basis and a second phase in which each unit was evaluated against the DEF system to evaluate the total fixed and energy costs for that unit. The initial screening process is outlined in the figure below.



The Phase 1 Screening uses assumed capacity factors and associated number of starts (in this evaluation 70% for the combined cycle units and 90% for the renewable bid). Using the bid values and DEF data for gas price, bid VOM, and bid start costs, a total energy cost is developed. That value is combined with a total fixed cost developed using DEF and bid data for capacity prices, fixed gas transportation, and firm transmission. Bids shorter than the study period (26 years for the screening) were back filled with energy and fixed costs equal to the self build on a $/kw basis. In this evaluation, transmission costs were not used since the transmission portfolios and their costs had not yet been developed.

Results of the Phase 1 Analysis (Total Cost in $/kwyr Levelized)



Final Screening Results

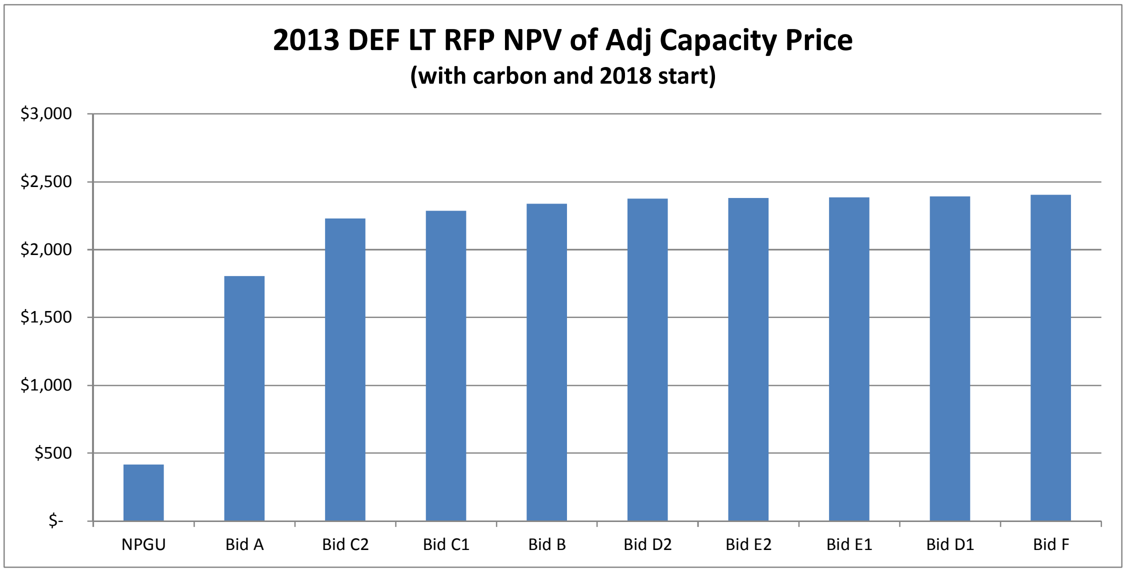
In the Phase 2 evaluation, fixed and variable costs for each unit were calculated. A proxy system in which required capacity was filled with a high dispatch cost unit (15,000 btu/kw heat rate) was developed to establish an hourly system dispatch price. Energy values for each bid were then calculated based on a comparison to a system marginal cost. Because of the variation in bid sizes, generic fillers were added (on a $/kw basis scaled to the size of the bids). Generic CC units were used to "back fill" (at the end of contracts), and generic CT units were used to "side fill" (add necessary capacity to equal the 1640 requested in the bid).

The analysis proceeded as described here with all calculations summed annually.

1. Calculate the dispatch cost for each unit based on bid data for heat rates, variable O&M, and energy charges.
2. Calculate a capacity factor for each unit by comparing the dispatch price to the hourly marginal cost for each hour in the period. Units were assigned a 4 hour minimum run time. (Except for Bid C which was 8 hours per the bid)
3. Calculate an "energy value" for each bid by calculating the difference between the marginal cost curve and bid dispatch cost when the bid is dispatched (considering minimum run times).
4. Calculate an energy value for any back fill and side fill capacity.
5. Calculate fixed costs for each unit including cost assigned for the sidefill and backfill capacities.
6. Calculate the total annual adjusted capacity price equal to the difference between the fixed costs of each bid and the energy value.
7. Calculate the NPV of the total annual adjusted capacity price for each bid.

The Final Screening Results involved combining individual bids into a resource plan which could meet DEF's system resource needs and then combining system requirements needs along with transmission screening costs into the Final Screening Results. The final economic screening did not eliminate any proposal but reflected a screening ranking of resource plans.

Results of the final (Phase 2) screening are shown in the figure below.



Minimum Technical Criteria Evaluation:

Bidder proposals were evaluated on an initial technical basis to assess the feasibility and viability of each proposal. As part of this technical evaluation, proposals were reviewed to ensure that they conformed to the Minimum Technical Requirements. The Minimum Technical Requirements are the technical "must have" elements of a proposal. The plan was to evaluate each Minimum Technical Requirement on a "Pass/Fail" or "Go/No Go" type basis. The Minimum Technical Requirements are identified in Table III-4 below.

FIGURE III-4
Minimum Technical Requirements

A. Environmental

* Preliminary environmental analysis performed and submitted to DEF [New Unit Proposals].
* Reasonable schedule for securing permits presented with evidence provided that it is reasonable to expect that permits can be secured in a timely fashion [New Unit Proposals].

B. Engineering and Design

* The project technology is capable of achieving the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].
* Operation and Maintenance Plan provided that indicates the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. Fuel Supply and Transportation Plan

* Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. Project Financial Viability

* For New Unit Proposals, evidence provided that it is reasonable to expect that the project is financially viable (assuming a power purchase agreement is in place with DEF) [New Unit Proposals].
* Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. Project Management Plan

* For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial within the time frame requirements of this RFP [New Unit Proposals].

Minimum Technical Requirements Evaluation Results.

DEF reviewed the Minimum Technical Requirements of each bidder proposal to ensure that the proposal contained sufficient documentation to demonstrate that they met all Minimum Technical Requirements. DEF established separate teams staffed with personnel with expertise in the areas of development and construction, engineering operations, environmental, financial viability, fuel, key terms and conditions, and transmission to review the bidder proposals for compliance with the Minimum Technical Requirements. Each team received the executive summaries of the proposals and only the portions of the proposals that dealt with its area of expertise. The economic evaluation team was the only team that had access to the pricing of the bidder proposals because the other evaluation teams did not need to know the pricing to perform the evaluation of the proposals on technical merits. This resulted in an impartial technical evaluation of the bidder proposals.

DEF's technical requirements evaluation uncovered issues that needed further clarification from all of the bidders. Clarifying questions were sent to the bidders and responses were received. While all bidders attempted to respond to the clarifying questions, the information provided did not resolve all the issues identified in the technical criteria review. Again, because DEF had a limited number of bidder proposals to evaluate, DEF elected not to disqualify any proposal from further evaluation, and DEF decided to consider the remaining technical criteria issues, as necessary, in any final qualitative evaluation of the proposals. If the Company's economic analysis in the RFP evaluation process eliminated the proposals with these technical criteria issues from further consideration, there was no need to resolve them. DEF decided that it could always seek to resolve the technical criteria issues later in the qualitative evaluation process or through negotiations with the bidders, if necessary.

The following Table summarizes that Minimum Technical Requirements review, indicating that DEF checked all bidder proposals for compliance with the Minimum Technical Requirements. DEF further evaluated all bidder proposals on the same based for the more detailed technical criteria review at the same time, again, because of the limited number of bidder proposals DEF received in response to the 2018 RFP.

Final "Over All" Minimum Technical Requirements (MTR) Review

Proposal #	A	B	C	D	E	F
Accepetd (√) Rejected (X)	√	√	√	√	√	√

Minimum Technical Requirements - Proposal Reviews By Sections

Proposal #	A	B	C	D	E	F	MTR Review Sections
Accepetd (√) Rejected (X)	√	√	√	√	√	√	A. Environmental
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	B. Engineering & Design
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	C. Fuel Supply Transportation Plan
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	D. Project Financial Viability
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	E. Project Management Plan

Note: Although various concerns were identified by Review Leads and addressed in DEF 12/26/13 Clarifyng Questions, bidders responses to the 12/26/13 Clarifying Questions were adequate for continued evaluation and review beyond the Minimum Technical Requirements

Preliminary Total Cost Economic Screening with Generator Interconnection and Transmission Integration.

DEF conducted a preliminary total cost economic screening that incorporated generator interconnection and transmission integration for the bidder proposals. Because none of the bidder proposals satisfied DEF's 2018 reliability need, DEF had to develop resource plans that combined bidder proposals together, with generic CC or CT units, and that included individual bidder proposals with generic units. In this way, the preliminary economic screening combined bidder proposals into a resource plan that could meet DEF's system resource needs with appropriate generation interconnection and transmission integration screening costs. The preliminary economic screening did not eliminate any bidder proposal. It reflected a screening ranking of the bidder proposal resource plans.

To develop the generation interconnection and transmission integration costs, for new and existing unit bidder proposals located inside the DEF system, the transmission screening study consisted of a power flow analysis by the Transmission Group. For the bidder proposals with projects that were not interconnected with the DEF transmission system, preliminary transfer analyses were performed to examine the impact on the DEF transmission system of a transfer from the host system of the proposal output to the DEF system. The transmission screening study assessed the impacts to the DEF transmission system and resulted in a list of required transmission facilities, and an estimated cost of the required facilities, for the bidder proposal resource plans.

A more detailed discussion of the resource plans with a chart of the plans used for transmission evaluation is presented below in the detailed evaluation discussion.

<u>Step 3: Selection of Short List.</u>

DEF did not select a Short List. There were threshold requirements and technical criteria issues with the bidder proposals and the necessary bidder proposal resource plans that prevented DEF from selecting a short list.

DEF understood from receipt of the bidder proposals that all of the bidder proposals required generic units to fulfill the reliability need for the Company. As a result, the technical criteria review of a resource plan including some or all of the bidder proposals involved the assessment of unplanned and undeveloped generic units. Each of these unplanned and undeveloped generic units presented technical requirement and criteria issues in addition to the issues with the bidder's proposed units. These issues for the generic units included, among other factors, the need to site, license, obtain environmental permits, engineer, design, and construct the unplanned and undeveloped generic units in the bidder proposal resource scenarios. Because of these issues, as explained in more detail below, the Company was not sure that it could even plan and build the generic units in time to meet its reliability need. Consequently, the Citrus County CC NPGU clearly ranked ahead of all the bidder proposals resource scenario alternatives for all the 2018 RFP technical requirements and criteria.

Because of the limited number of bidder proposals, however, DEF elected to continue to evaluate the bidder proposals subject to all requirements of the 2018 RFP. DEF decided to continue the economic evaluation of all the bidder proposals to determine if there was some combination of them with generic units that offered superior value to DEF's customers than the Citrus CC NPGU. If the economic evaluation revealed such a favorable bidder resource plan proposal, DEF would then evaluate the qualitative risks associated with the generic units in the bidder proposal resource plan to determine if they could be overcome or satisfactorily mitigated. If the economic evaluation revealed that no bidder proposal resource plan was superior to the Citrus CC NPGU, there was no need to address the qualitative risks associated with the technical requirements and issues with the bidder proposal resource plans. DEF informed the bidders of this decision explaining that, because of the limited number of proposals DEF received in response to the 2018 RFP, DEF was continuing to evaluate all proposals utilizing all steps of the RFP process as may be necessary in its evaluation of their proposals.

Step 4: Detailed Evaluation

Introduction.

Due to the fact that (1) DEF received a limited number of proposals; (2) each individual proposal was at least 1,000 MW below the proposed RFP Citrus CC capacity of 1,640 MW; and (3) the total bid capacity was over 300 MW shy of the proposed RFP 1,640 MW of capacity need, DEF determined that it was required to build DEF generation in any and all combinations of the proposals that were provided. Originally in the development of the RFP, DEF selected the

Citrus CC as the least cost, self-build generation alternative from all internal resources available to DEF. Thus, the RFP was seeking competitive proposals to the Citrus CC unit as outlined in the DEF 2018 RFP. The DEF Citrus CC proposal of 1,640 MW was the only proposal that reliably meet the RFP bid requirements.

As stated in the RFP, DEF's analyses would utilize Generic CT and CC plants to complete the resource plans. Often in RFPs, DEF would use the Generic Units to backfill proposals that did not extend out the entire planning review period. Typically, the generic units would be place holders for future DEF resources so that DEF could insure a reliable resource plan given a bidder(s) shortfall in capacity due to a proposal(s) term(s) of service years. By nature, the future forecasting of DEF generic units would allow DEF significant enough time to develop the Generic Units into feasible, site specific alternatives that could be refined so that the required regulatory and environmental permits could be obtained for those future resources.

Due to the 2018 in-service requirements of the RFP (and thus DEF's need to seek viable market alternatives to DEF's Citrus CC), DEF does not believe that it could easily and adequately develop and obtain regulatory approval for such smaller generic combined cycle unit that would be required to supplement individual bid proposals for a 2018 in-service date. However, DEF believes it could successfully develop generic combustion turbine units into a feasible alternative that could obtain the required regulatory and environmental permits, although additional developmental time would be required.

Despite potential feasibility concerns, DEF allowed both the Generic CC and Generic CT as available resource options to determine if the detailed evaluation results would produce enough system benefits to justify continued evaluation of an alternative resource portfolio that could potentially benefit DEF even though, as discussed above, such a portfolio inherently had permitting and construction risks associated with DEF's own generic unit. DEF commenced with the Detailed Evaluation of all submitted proposals subject to the continued evaluation of all proposals utilizing all steps of the RFP process as necessary.

Detailed Evaluation

The Detailed Evaluation consisted of the Initial Detailed Evaluation followed by a Final Detailed Evaluation. In the Initial Detailed Evaluation, DEF combined the three steps, (a) the Optimization Analyses, (b) Technical Criteria Evaluation and (c) the Transmission Reviews, for a combined review of initial competing alternative plans against the self-build alternative.

As contemplated in the RFP, none of the bids received was directly comparable to the NPGU in capacity or in duration. As a result, DEF created a series of portfolios utilizing the proposal bids and generic units in combination to meet the required need. DEF also used these portfolios as the basis for transmission studies to establish the transmission system upgrade costs associated with each alternative.

In addition, because the evaluation was conducted over the 35 year period corresponding to the projected life of the NPGU, capacity was required to "back fill" at the conclusion of the proposed contracts. DEF used a hypothetical 450 MW future combined cycle as to provide necessary capacity to balance the portfolios. In each case, the back fill unit was put into service at the end of a given contract.

Finally, in constructing the portfolios, because three of the bids were submitted by a single corporate owner (Bids D, E, and F), and each bid was for a capacity of 150MW or less, these bids were evaluated as a group.. This grouped bid (made up of Bids D1, E1 and F) was designated Bid G.

Bid B was for only 40 MW. This capacity is not large enough to cause a deferral of future capacity in the resource plans used for this evaluation. Bid B was combined with other bids in some portfolios and was separately evaluated in combination with the NPGU to demonstrate whether the energy value derived from this resource would produce value in the portfolio above the proposed capacity and energy charges.

Fuel gas for each of the bidding and generic units was assumed to be supplied via existing contracts where available and from available pipeline capacity as needed. Transportation pricing was adjusted to provide access to onshore and unconventional (shale resources) for all portfolios.

a. Optimization Analyses

In the Optimization Analyses, DEF analyzed each short list bidder proposal's value by developing an optimal resource plan around each proposal as shown below:

Scenario	Bid Units	Generic 2018 Units	Backfill Units
1	Citrus CC (NPGU)	None	None
3	Bid C1 Bid A Bid G Bid F	2 CT (188MW each)	2034 450 MW CC 2043 450 MW CC 2044 450 MW CC
5	Bid A Bid G	2x1 CC (793 MW)	2043 450 MW CC 2044 450 MW CC
6	Bid C1 Bid A	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
7	Bid C1 Bid G Bid B	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
8	Bid A	2x1 CC (793 MW) 2 CT (188MW each)	2043 450 MW CC
9	Bid G	2x1 CC (793 MW) 2 CT (188MW each)	2044 450 MW CC
10	Bid C1	2x1 CC (793 MW) 2 CT (188MW each)	2034 450 MW CC
11	Citrus CC (NPGU) Bid B	None	None

The objective of the portfolio development, in each case was to create a portfolio of approximately 1,640 MW that could be evaluated in comparison with the NPGU. Discrete sized generic units (as identified in the table above) were used, so each portfolio was slightly different in total capacity, but the differences were small enough that DEF believes these differences did not produce any material bias in the results. These portfolios were developed both for use in the evaluation of system costs and for use in the transmission evaluations described earlier.

The development of the above Generation Scenario Plans were then combined with the items B and C above to determine the cumulative present value of revenue requirements ("CPVRR") of each plan as shown in the Summary of Initial Detailed Evaluation section.

b. Transmission Reviews

As discussed in the RFP, DEF recognized that a reduction in the available generation in the immediate vicinity of the Crystal River Energy Center related to the retirements of Crystal River Units 1, 2, and 3 would result in a need for significant transmission upgrades on the DEF system. As a result, transmission studies with evaluations of the portfolios and the specific locations of the units, both bidders and generic units in each portfolio, to identify the costs of transmission projects required was a critical part of the overall evaluation. In order to minimize the impacts of transmission on the results, DEF assumed that the generic units would be sited in locations deemed to partially mitigate the impact of the Crystal River unit retirements, i.e. near Crystal River or near DEF's Central Florida Substation. These selections are reflected in the portfolios.

Each of the portfolios was evaluated for transmission impacts. As identified in the RFP, retiring generation at Crystal River made Citrus County a preferred location for the new generation. It was anticipated that location of generation away from this area would cause additional transmission impacts. However, the impacts associated with each portfolio had be evaluated based on transmission modeling based on the specific locations of each bid and selected locations for generic units as shown in the Table above. Actual transmission modeling work for the transmission analyses was performed by Power Grid Engineering LLC ("Power Grid"), an independent engineering company, under the supervision of the DEF Transmission Planning Group. Power Grid is a recognized electric utility engineering company with substantial expertise in modeling transmission systems and performing the standard electric utility transmission system analyses for any proposed generation additions to a transmission system.

Power Grid used industry-leading transmission planning engineering tools similar to our own transmission planning engineering tools to perform these analyses and DEF transmission planning staff reviewed and validated their models and model results.

DEF initially performed a transmission screening study for all proposals to the 2018 RFP. For the 2018 RFP proposals within DEF's system, a power flow analysis was performed. For the 2018 RFP proposals that were not interconnected with DEF's transmission system, preliminary transfer analyses were performed. Both sets of transmission screening studies assessed the impacts to the DEF transmission system by providing a list of required transmission facility additions or modifications and an estimate of the cost of the transmission facility additions or modifications. These transmission screening studies were industry-standard studies consistent with DEF's internal standards and both FRCC and NERC reliability standards. For example, 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 2018 RFP proposals that DEF uses for all of its planned or projected transmission facility additions or upgrades on its own transmission system. All potential solutions were then subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution.

All of the 2018 RFP proposals, except the Company's self-build next planned generating unit proposal, were evaluated in the portfolios identified above, also referred to as transmission groups. The transmission groups are shown below. As noted, the groupings of units are the same as those identified in the generation portfolios above.

Resource Plan Alternative	Gen Plan #s (Trans Plan #s)	Description	MW	Units	Location
I) Self Build Only	1	NPGU	1,640	Citrus 4x2 CC	500 Kv 1st & CR1&2 on for summer/230 Kv Wtr
	2	NPGU	1,640	Citrus 4x2 CC	230 Kv 1st & CR1&2 off for summer/500 Kv Wtr
II) Total Non DEF Proposals	3 (2B)	A, B, C, G		Bids	Bidder Sites
+ DEF Generic Units		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,715		
	4 (2C)	A, B, C, G		Bids	Bidder Sites
		DEF Generic		2-CTs	Citrus
		Total MW	1,715		
III) Approx 900 Block Proposals	5 (3A)	A, G		Bids	Bidder Sites
+ DEF Generic Units		DEF Generic		2x1 CC	Citrus
		Total MW	1,693		
	6 (3B)	A, C		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		Total MW	1,689		
	7 (3C)	B, C, G		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		Total MW	1,729		
IV) Individual Proposals	8 (4A)	A		Bid	Bidder Site
+ DEF Generic Units		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,688		
	9 (4B)	G		Bid	Bidder Site
		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,572		
	10 (4C)	C		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,568		
	11	B		Bids	Bidder Sites
		NPGU		4x2 CC	Citrus
		Total MW	1,680		

In reviewing Transmission Groups, DEF included the costs of any necessary transmission network upgrades that were determined to be necessary to deliver the output of the new generator and/or power transfers from existing generation sources to DEF load. If the individual proposal Response Package included costs on other third party systems as a DEF responsibility, then those costs would be included in the evaluation.

The transmission network upgrade costs are based on all modifications (new facilities and facility upgrades) to the DEF transmission system that are necessary to physically transfer the proposed power from the DEF system receipt point to the load center consistent with reliability standards for 2018 Summer and 2018/19 Winter conditions. The latest available Florida Reliability Coordinating Council ("FRCC") peak load flow case (updated as necessary to reflect the latest available information) was used as the basis for determining the transmission network upgrade modifications needed.

The Final Summary Results of the Transmission Economic Reviews are as follows:

Summary of Estimated Transmission Cost by Scenario				
Scenario				
3	2B - Combined Transmission Cost	$	186.6	Million
4	2C - Combined Transmission Cost	$	190.3	Million
5	3A - Combined Transmission Cost	$	146.0	Million
6	3B - Combined Transmission Cost	$	161.9	Million
7	3C - Combined Transmission Cost	$	145.7	Million
8	4A - Combined Transmission Cost	$	129.8	Million
9	4B - Combined Transmission Cost	$	202.4	Million
10	4C - Combined Transmission Cost	$	135.3	Million

Values are nominal dollars for 2018 in service projects

Implementing DEF Transmission BES upgrades may impact other host utility BES networks and would require additional detailed transmission impact and facility reviews if an individual or combination of bids were selected to the Final List(s). DEF recognized a qualitative risk around the potential that transmission engineering and construction might result in project delays beyond the May 2018 in service date. The nominal costs shown above were assumed to be spread over the years 2015 through 2018 to mimic a typical construction schedule and converted to revenue requirements for use in the economic analysis.

Economic Evaluation

While the screening analysis of the proposals compared the cost of 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 the total DEF system cost compared to a Base Case. The impact on total system costs is important because it shows the net impact on the customer of choosing an alternative, including both the project cost and the impact the alternative would have on system 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 the impact the alternative would have on DEF's other purchased power operating costs.

DEF combined the above three steps, (a) the Optimization Analyses, (b) Technical Criteria Evaluation and (c) the Transmission Reviews, for a combined review of initial competing alternative plans against the self-build alternative.

Each portfolio was evaluated over the 35 year period corresponding to the projected life of the NPGU. DEF used the Planning and Risk module of Ventyx's Energy Portfolio Manager (EPM) modeling software to derive the production costs including fuel, non-fuel O&M, emissions and reagent costs for the full portfolio. Planning and Risk uses Ventyx's PROSYM calculation engine to calculate hourly dispatch, performance and costs for each unit on the DEF system. Fixed costs including capital revenue requirements, fixed gas transmission charges, capacity payments and fixed O&M were calculated. These two sets of results were combined to develop total portfolio costs expressed as Cumulative Present Value Revenue Requirements for each portfolio.

Summary of Initial Detailed Evaluation Results

DEF determined the cumulative present value of revenue requirements ("CPVRR") of each scenario developed around the resource plans described. The results of the initial detailed evaluation are based on detailed production cost modeling and fixed cost analysis of the RFP plan scenarios over a 35 year study period. The results are shown as differential CPVRR comparing each of the plan scenarios with TP1 – the Self-Build NPGU. Negative differentials indicate that a scenario is more expensive (less favorable).

Initial Detailed Evaluation Results

		Differential vs. NPGU $M CPVRR		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($951)	($908)	($773)
TP 5	Bids A and G + Generic CC	($583)	($569)	($438)
TP 6	Bids A and C1 + Generic CC	($512)	($510)	($466)
TP 7	Bids B, C1, and G + Generic CC	($685)	($646)	($620)
TP 8	Bid A + 2 Generic CTs + Generic CC	($376)	($366)	($171)
TP 9	Bid G + 2 Generic CTs + Generic CC	($647)	($631)	($403)
TP 10	Bid C1 + 2 Gen CTs + Generic CC	($457)	($444)	($308)
TP 11	Self-Build NPGU and Bid B	($20)	($4)	($50)

Final Detailed Evaluation

DEF further reviewed the proposals from the Initial Detailed Evaluation in a robust review of competing alternative plans against the self-build alternative. DEF utilized a High Gas Price Case and a No CO2 Price Case for this review. DEF determined the cumulative present value of revenue requirements ("CPVRR") of each scenario developed around the resource plans for; (1) Reference Case (as shown above and utilized here for reference purposes); (2) High Gas Price Case; (3) No CO2 Price Case. A summary of these differential vs. NPGU (Citrus CC1) CPVRR in millions of dollars are shown below.

Rule 25-22.081(7) requires utilities to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a nonutility generator by made. Since entering into a purchase power agreement is similar to taking on additional debt, the cost of imputed debt was applied to proposals to ensure that the total costs of proposals include the marginal impact of the fixed future commitment on DEF's capital structure. The annual additional equity cost of imputed debt on a revenue requirements basis is calculated as:

Annual Additional Equity Cost =
Risk Factor * Present Value of Future Fixed Payments
* (Cost of Equity Rate – After Tax Cost of Debt Rate)
* Equity Ratio / (1 – Tax Rate)

where the Risk Factor and Present Value of Future Fixed Payments are calculated consistent with the S&P Standard Methodology.

This additional cost is the direct result of having the transaction cause DEF to incur fixed future payment obligations. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments. The Risk Factor is the percentage of the future fixed payments to be added to balance sheet debt and depends on a number of factors, including the conditions of a purchased power proposal, counterparty risk, and regulatory cost recovery risk. The biggest factor in selecting a risk factor is the degree of certainty and timeliness of regulatory recovery by the utility. Based on Standard & Poor's recommendation, utilities in supportive regulatory jurisdictions with a regulatory precedent for timely and full cost recovery of fuel and purchased-power costs, may use a risk factor as low as 25% of which DEF used for this analyses.

Results of analysis

The results of the final detailed evaluation are based on detailed production cost modeling and fixed cost analysis of the RFP plan scenarios over a 35 year study period. The results are shown as differential CPVRR comparing each of the plan scenarios with TP1 – the Self-Build NPGU. Negative differentials indicate that a scenario is more expensive (less favorable).

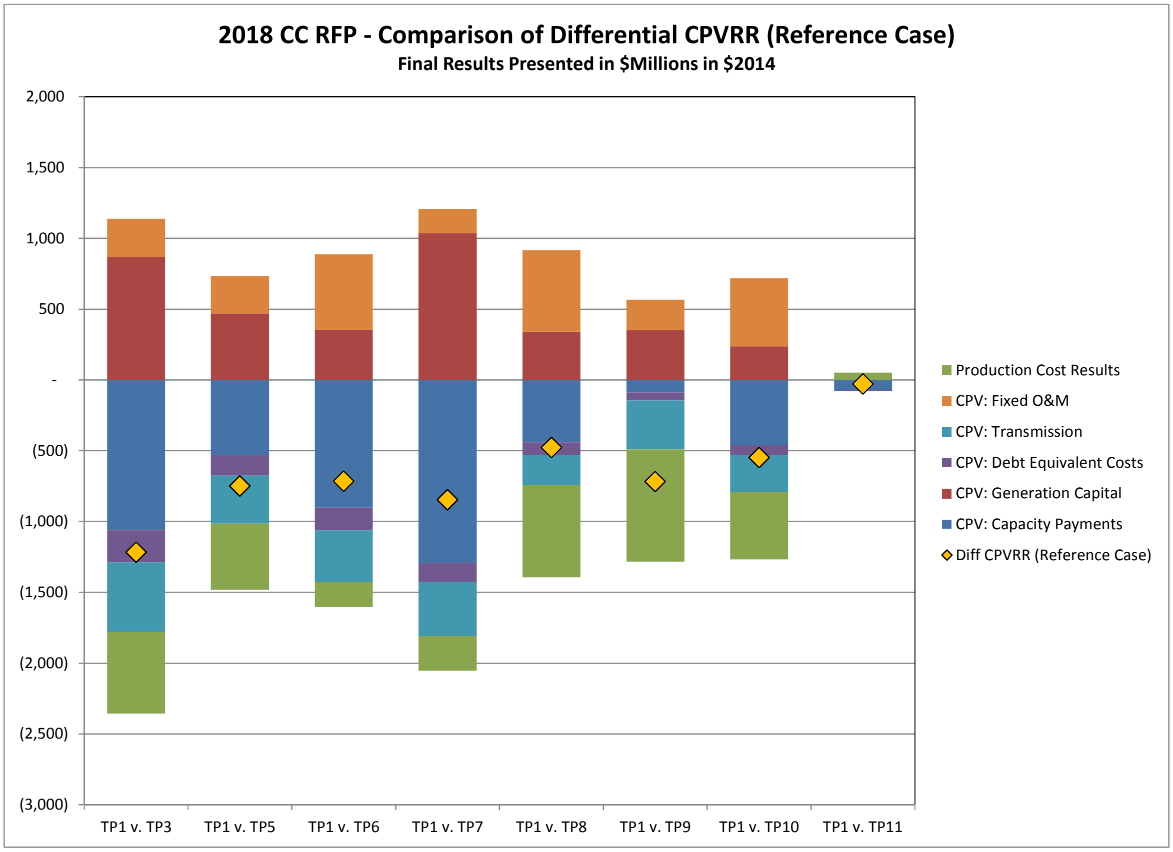
		Differential CPVRR \$2014 in \$Millions		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	\$0	\$0	\$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	(\$1,218)	(\$1,171)	(\$1,037)

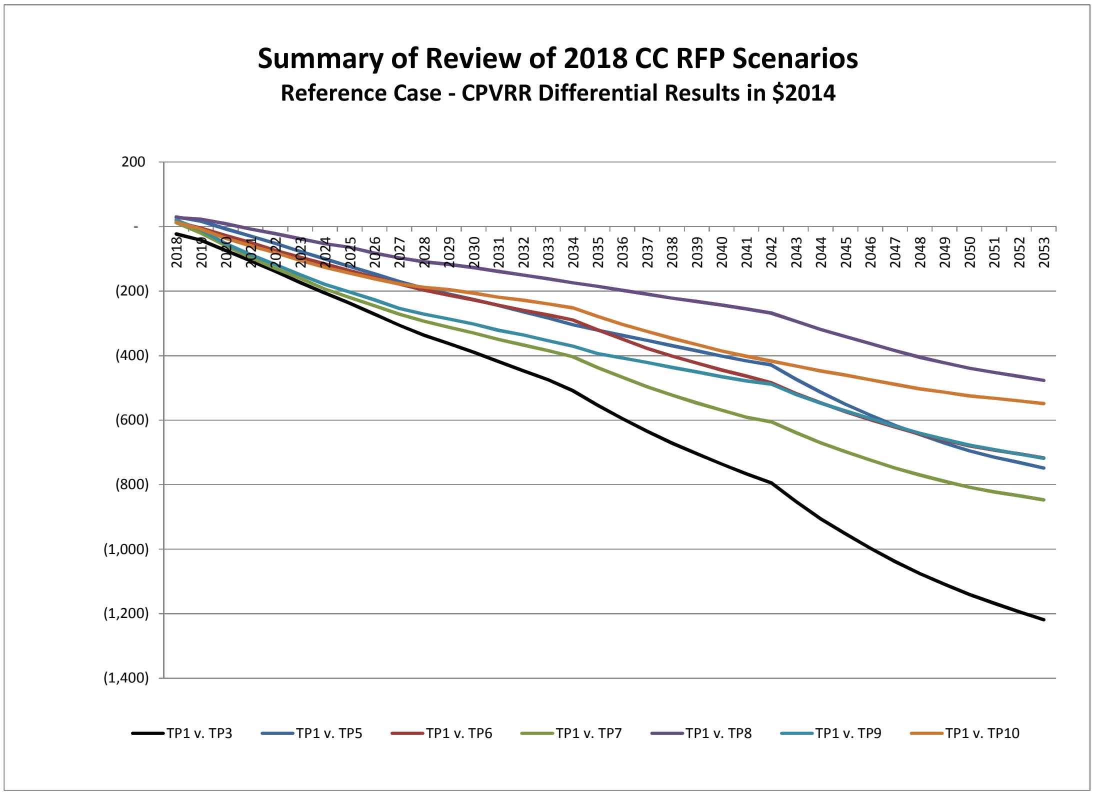
TP 5	Bids A and G + Generic CC	($748)	($731)	($600)
TP 6	Bids A and C1 + Generic CC	($705)	($699)	($655)
TP 7	Bids B, C1, and G + Generic CC	($847)	($811)	($784)
TP 8	Bid A + 2 Generic CTs + Generic CC	($477)	($464)	($269)
TP 9	Bid G + 2 Generic CTs + Generic CC	($718)	($693)	($464)
TP 10	Bid C1 + 2 Gen CTs + Generic CC	($548)	($535)	($399)
TP 11	Self-Build NPGU and Bid B	($29)	($13)	($59)

In terms of cumulative present value of revenue requirements (CPVRR), the Citrus CC was found to be was found to be approximately $477 million less expensive than the least cost alternative portfolio in which Citrus was not constructed. The charts below, Figures XX and YY along with the table above, show the results of the analysis. The table shows the total differential CPVRR between the Citrus CC (NPGU) and the other portfolios. Figure XX shows the difference in the total CPVRR with a breakdown into major components of the difference. Figure 12 shows the results on an annual basis.

Bid B in combination with the Citrus CC did not provide a lower CPVRR over the period compared to the Citrus CC alone. This demonstrated that Bid B did not provide value as an energy resource in the portfolio at the capacity and energy rates proposed.

The results of the detailed financial analysis of the proposals and the alternate scenarios demonstrate that the Citrus CC is clearly the most cost-effective alternative for supplying generation to meet the needs of the DEF customer.


2018 CC RFP - Comparison of Differential CPVRR (Reference Case)
Final Results Presented in $Millions in $2014
2,000
1,500
1,000
500
-
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
TP1 v. TP3
TP1 v. TP5
TP1 v. TP6
TP1 v. TP7
TP1 v. TP8
TP1 v. TP9
TP1 v. TP10
TP1 v. TP11
Production Cost Results
CPV: Fixed O&M
CPV: Transmission
CPV: Debt Equivalent Costs
CPV: Generation Capital
CPV: Capacity Payments
Diff CPVRR (Reference Case)

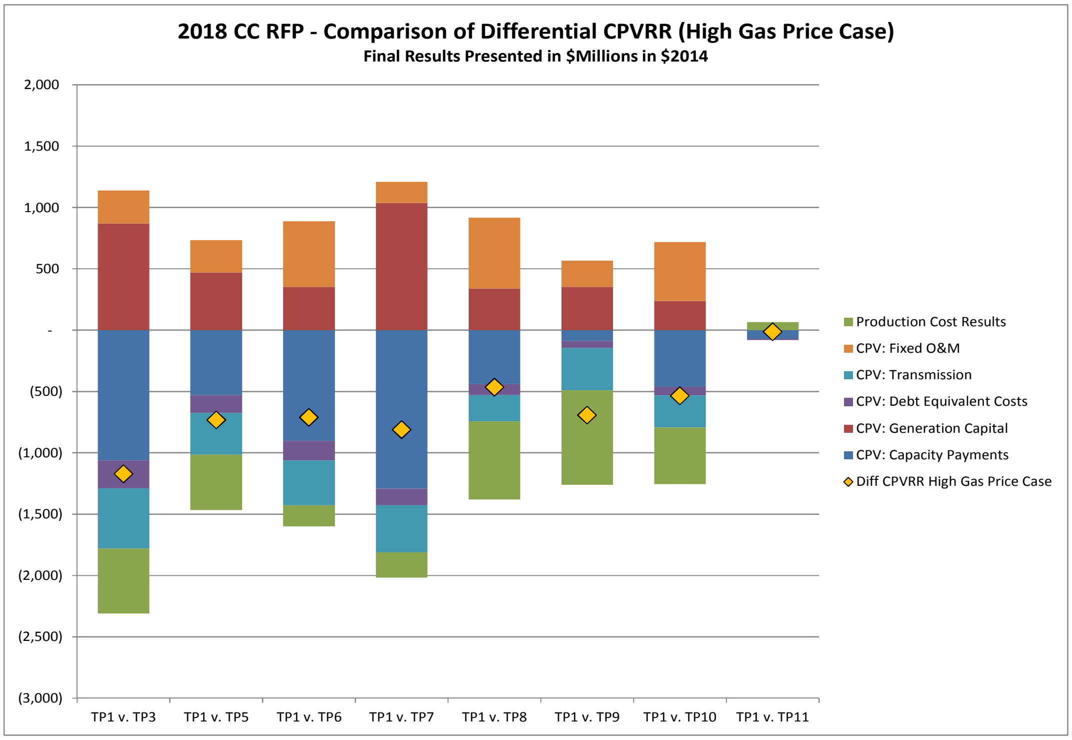


Sensitivities

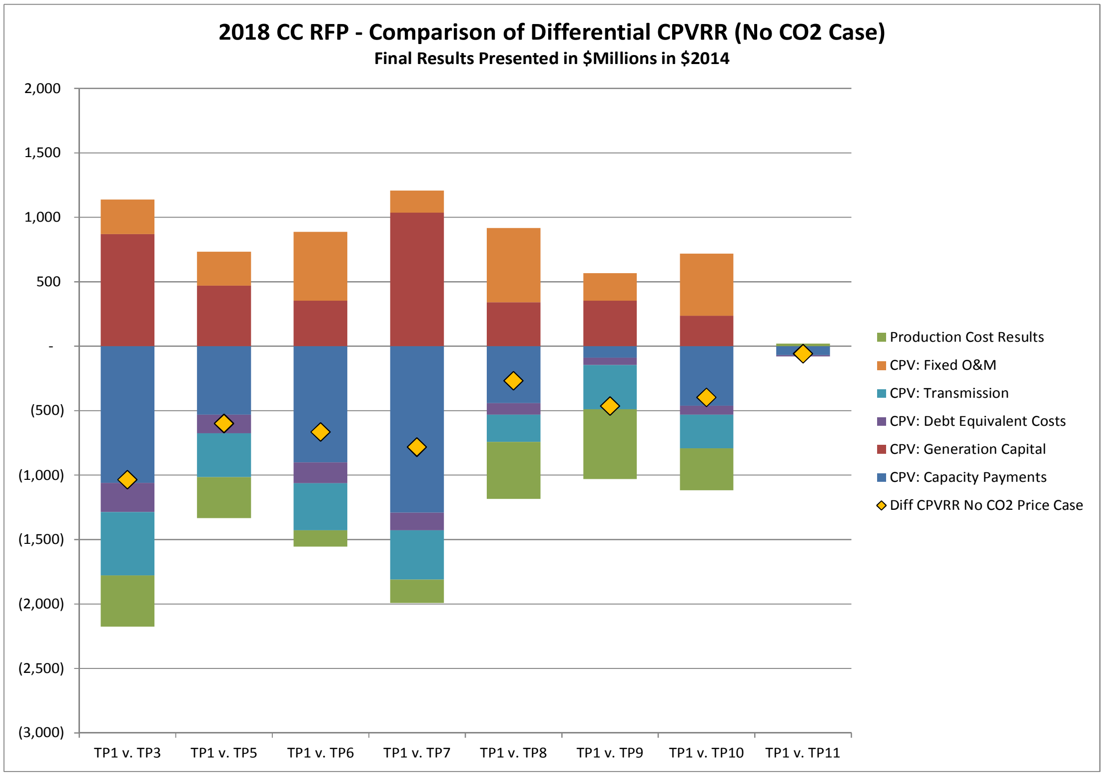
To confirm the results and establish that the selection of the Citrus CC as the most cost effective alternative to meet the needs of DEF customers is robust, DEF ran two sensitivities a high gas price case, and a no CO2 price case. Results of these sensitivities are shown in the Table and in the figures below.

In general, the application of the high gas price to the cases caused the alternate cases to have a smaller differential from the Citrus CC than in the reference case. This result is somewhat counter intuitive since in general the Citrus CC is the most efficient generator analyzed. A detailed review of the results showed that most of the difference in the cases is actually attributable to increased operation of the coal fired Crystal River Units 4 and 5 displacing operation of the marginal CC unit from the proposals. This confirms that the result is robust for two reasons (1) the shift in the values is very small and the Citrus CC is still preferred over any of the portfolios without Citrus by over $400 million and (2) since the differential is caused in part by increase in the coal fired utilization and that generation is close to its maximum availability, a further rise in the gas price is not anticipated to make significant further reductions in the differentials.

The high gas price produced more value for Bid B in combination with the Citrus CC (TP11), but did not produce sufficient value to offset the proposed energy and capacity charges.



DEF also examined a case in which there was no CO2 regulation. The CO2 price from the base reference case was set to zero and no emissions restrictions were adopted for greenhouse gases. This sensitivity reduced the differential between the Citrus CC portfolio and all the portfolios in which the Citrus CC was not constructed. The Citrus CC was still preferred by over$250 million in CPVRR compared to the next most favorable alternative portfolio. This change in the differentials results from the effective removal of an efficiency penalty in the form of a charge for emissions rate. Since the comparison of portfolios is between different gas fired alternatives, the emissions rate for each portfolio is effectively a measure of portfolio efficiency. A secondary effect observed here is the increase in coal fired generation in many of the competing portfolios as the emissions penalty for the coal fired emissions is removed.



Selection of Final List

DEF stated in its RFP that it would develop a Final List based on the detailed evaluation of the short-listed proposals, but that in the event that the Citrus CC was found to be clearly superior to the other alternative, a Final List would not be selected. Based on the results of the detailed analysis, the Citrus CC was found to be clearly superior to the other alternatives. Thus, DEF announced on May 13, 2014 that the Citrus CC was the most cost-effective alternative for adding electric generation to serve its customers' needs. This announcement concluded the RFP process.

10. Conclusions—The Need for The Citrus CC

The Citrus CC unit will be a state-of-the-art, highly efficient, environmentally benign unit, and it will be built at a site that is well-suited to accommodate the planned expansion of DEF's generation system. The plant is the most cost-effective alternative available to DEF. It will provide needed efficiency and cost-effectiveness to DEF, enabling DEF to achieve substantial savings for its ratepayers over the life of the plant.

For these reasons, DEF seeks an affirmative determination of need for the Citrus CC unit and associated transmission facilities to meet DEF's needs for electric system reliability and integrity and to enable DEF to continue to provide adequate electricity to its ratepayers at a reasonable cost. DEF determined to seek this approval only after conducting a rigorous internal review of supply-side and demand-side options, and after soliciting and evaluating competing proposals submitted by interested third party suppliers. The need for additional generating capacity cannot be cost-effectively deferred or avoided by additional demand-side options.

The addition of the Citrus CC capacity is necessary for the Company to meet its commitment to provide an adequate and reliable power supply. The Citrus CC will allow the Company to satisfy its Reserve Margin and loss of load probability criteria while maintaining an appropriate level of physical reserves for the DEF system.

The Citrus CC is designed to be a highly efficient state-of-the-art combined cycle unit with minimal environmental impact. It will be fired with natural gas, a clean and environmentally friendly fuel that will be supplied from a new natural gas transportation resource and will be able to access the new sources of unconventional gas from on-shore North America. The Citrus CC will be sited on land contiguous with the existing Crystal River Energy Center and will achieve synergy savings in transmission, water, and transportation resources.
The Citrus CC unit will meet the Company's need to be able to provide adequate electric service at a reasonable cost to its customers.

Adverse Consequences of Not Building the Citrus CC

If the Citrus CC unit is delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2018 in the most reliable and cost-effective manner. This would expose the Company's customers to a greater risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. To illustrate, DEF has retired CR3 and currently must retire CR1 and CR2 and will do so by 2018. DEF, therefore, faces a need for reliable generation in 2018. In addition, these retirements lead to DEF and Florida electric grid reliability issues in the event the addition of combined cycle generation in the vicinity of Citrus County is delayed beyond 2018. To avoid reliability issues for the Florida grid, the Citrus CC needs to be built and placed in commercial operation in 2018. Even without an interruption in service, without the efficient Citrus CC unit, DEF's customers would be subject to higher fuel costs as less efficient units are used to serve their needs. Delaying the Citrus CC beyond 2018, delays these benefits to customers. For all these reasons, DEF needs to move forward with and place the Citrus CC in commercial operation in 2018.

APPENDIX A

Duke Energy Florida, Inc.

10/8/13

Request for Proposals

For Long-term Power Supply Resources With an In-service Year of 2018

DEF 2018 RFP

DUKE ENERGY®

DEF 2018 RFP Document
TABLE OF CONTENTS

Attachments:

DEFINITIONS

Presented below are DEF definitions of critical terms used in this RFP and solicitation process. Other definitions are included in the Key Terms & Conditions.

Area Control Error (ACE): The difference between scheduled and actual interchange measured by a control area, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC): AGC is the automated regulation, within predetermined limits, of the power output of electric generators within a prescribed geographic area in response to changes in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or the established interchange with other geographic areas. This regulation will be accomplished through communication links between DEF's Energy Control Center dispatch computer and each generator equipped with such AGC control.

Availability Adjustment Factor (AAF): A measure of a Facility's or Bidder's ability to provide capacity in the amount requested by DEF. The Availability Adjustment Factor is defined in Section 2 of the Key Terms and Conditions (Attachment A).

Bidder: Any entity that submits a proposal to DEF in response to this RFP.

Block Schedule: A transaction where the generator or sending control area adjusts its generation on a 10 minute ramp to accommodate a static amount of capacity represented by an energy profile which is scheduled to flow to a load or sink control area.

Dynamic Schedule: A telemetered reading that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling generation to or from another control area.

Equivalent Availability Factor (EAF): Sum of the Equivalent Unplanned Derated Hours (EUDH) and Equivalent Planned Derated Hours (EPDH) subtracted from Available Hours (AH) and divided by Period Hours (PH). The method for calculating the Equivalent Availability Factor is defined in the discussion of Section II.H of the Response Package.

Equivalent Forced Outage Rate (EFOR): Sum of Forced Outage Hours (FOH) and Equivalent Forced Derated Hours (EFDH) divided by the sum of Forced Outage Hours (FOH) and Service Hours (SH). The method for calculating the Equivalent Forced Outage Rate is defined in the discussion of Section II.H of the Response Package.

Existing Unit Proposal: A bid to provide capacity and energy from a specific generating unit already in commercial operation and identified by the Bidder.

Facility: All of the equipment, property, buildings, and generation and transmission-interconnection facilities necessary to allow the Bidder to fulfill its proposal to provide capacity and energy to DEF pursuant to this RFP.

Forced Outage: An unplanned component failure (immediate, delayed, postponed, or start failure) or other condition that requires the unit be removed from service immediately, within six hours, or before the end of the next weekend, consistent with industry standards.

Frequency Control: The capability of a generator to automatically respond to frequency deviations by increasing or decreasing its gross real power output as a result of governor action.

For generation resources located inside the DEF control area or dynamically telemetered into the DEF control area:
The Bidder's generator(s) shall be equipped with fully functional governors with droop adjustable from 2% to 6% and nominally set at 4%. The governors will be fully responsive to frequency deviations exceeding 0.036 Hertz (Hz).

For generation resources located outside the DEF control area:
The Bidder shall comply with the frequency response requirements of the host control area.

Fully Dispatchable: A generating resource is Fully Dispatchable when DEF makes the sole decision to dispatch/operate the unit with exceptions granted for maintenance and testing. For generating resources located in DEF's control area and to qualify as Fully Dispatchable, the generator must be equipped with and controllable through an AGC link with DEF's Energy Control Center. For offers relating to a unit-contingent generating resource located outside of DEF's control area and to qualify as Fully Dispatchable, the generator must provide Dynamic or a combination of Dynamic/Block scheduling that is tied into DEF's Energy Control Center. Fully Dispatchable generating facilities must be available for DEF's dispatch instructions and control, in accordance with specific operating parameters (minimum load, ramp rates, start time, maximum starts per year, annual operating hour limit, and minimum run time) with the specifications for such parameters set forth by the Bidder in its proposal. Unit-contingent resources committed to DEF but not dispatched by DEF for a particular period will not be available to other market participants.

Fully Schedulable: A System Power Proposal is Fully Schedulable when its output is controlled and determined by a schedule specified by DEF. While such specific schedule would be established under the terms of an agreement with DEF, DEF expects that a schedule would be tentatively established on a day-ahead basis (i.e., by 4:00 p.m. for deliveries on the following day) and revised as necessary on a day-to-day basis to respond to unanticipated operating requirements subject to normal utility practice.

Minimum Technical Requirements: The minimum technical requirements that all proposals are required to meet and with which a Bidder's compliance will be assessed in Step 3 of the evaluation process (see Section III.B.3.b.i). Minimum Technical Requirements must be met to proceed beyond Step 3 of the evaluation process.

New Unit Proposal: A bid to provide capacity and energy from a new unit or block of units which is not currently in commercial operation and which is specifically identified by the Bidder.

Official Contacts: The DEF representative, and designee, identified in Section I.E of this RFP to whom all contact regarding this solicitation process must be made.

Power System: Physically connected generation and transmission facilities operated as an integrated unit under one central management or operating supervision.

Response Package: The second section of this RFP that identifies the information and schedules that Bidders are required to provide in their proposals to DEF.

RFP Project Team: A group of individuals with backgrounds in a number of disciplines necessary to conduct a thorough evaluation of each proposal. The individuals may be Duke Energy employees or consultants.

Seasonal Contract Capacity (SCC): The Summer Contract Capacity and the Winter Contract Capacity, as applicable, with the summer and winter seasons as defined in Section II.E of the Response Package (attachment C). For New and Existing Unit Proposals, the capacities are the values specified by the Bidder in Schedule 1 of the Response Package in the section labeled "Seasonal Contract Capacity." For System Power Proposals, the capacities are the values specified by the Bidder in Schedule 2 of the Response Package.

Self-Build Option: The proposal that will be developed by DEF and submitted to the RFP process along the same schedule as any other offers submitted in response to the RFP. Certain filing requirements do not apply to the Self-Build Option, including for example, acceptance of Key Terms and Conditions (since there would be no power purchase agreement for a Self-Build Option), and informational requirements regarding Bidder experience and credit quality.

Summer Contract Capacity: The maximum capacity (MW) the Facility can sustain during the Summer period, less the capacity utilized for station service or auxiliaries, and adjusted for losses to the delivery point in the DEF control area.

System Power Proposal: A bid to provide capacity and energy from a Power System.

Technical Criteria: Attributes of proposals that go beyond the Minimum Technical Requirements and which offer value to DEF's customers, as evaluated in Step 3 and as described in Section III.B.3.b.ii.

Threshold Requirements: The minimum requirements that all proposals are required to meet and with which a Bidder's compliance will be assessed in Step 1 of the evaluation process (reference Section III.B.1).

Unit Reliability Program: The program for unit operations and maintenance identified by Bidders. This program may take the form of identification of plans to conclude one or more

Long Term Service Agreements (LTSA) with equipment vendors, description of a self-performed maintenance plan, demonstration of a track record of unit availability in units committed to this proposal or other similar units.

Voltage Control: The ability to modify generator terminal voltage by varying the current in the generator's field winding either automatically by appropriate control mechanisms or manually by the operator.

For generation resources located inside the DEF control area or dynamically telemetered into the DEF control area:
The Bidder's generator(s) shall be equipped with fully functional automatic voltage regulators that will control the generator terminal voltage according to a Voltage Schedule provided by DEF unless directed otherwise by the DEF Energy Control Center.

For generation resources located outside the DEF control area:
The Bidder shall comply with the voltage control requirements of the host control area.

Winter Contract Capacity: The maximum capacity (MW) the Facility can sustain during the Winter period, less the capacity utilized for station service or auxiliaries, and adjusted for losses to the delivery point in the DEF control area.

1

I. INTRODUCTION

A. Overview of DEF 2018 Request for Proposals ("RFP" or "DEF 2018 RFP")

Duke Energy Florida ("DEF" or "Company") is seeking proposals from potential suppliers of electric generating capacity and associated energy as described herein. In this RFP, DEF is soliciting proposals for alternatives to the Company's next planned generating unit ("NPGU"), which is approximately 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018.

DEF invites all potential participants to submit bids in accordance with the terms and conditions of this RFP. DEF's NPGU is a natural gas-fired combined-cycle ("CC") resource generally described in Section IV of this RFP. However, the Company will consider other resource types. Proposals received shall be evaluated in accordance with applicable rules, regulations, and statutes. The following are summaries of the RFP documents along with some Key RFP information.

This DEF 2018 RFP document includes the following four Attachments:

- Attachment A: Key Terms and Conditions
- Attachment B: DEF 2013 Ten-Year Site Plan ("TYSP")
- Attachment C: Bidders Response Package (Instructions)
- Attachment D: Bidders Response Schedules/Forms (Excel Version)

Summary of some key DEF 2018 RFP information:

- Capacity and energy must be from a dispatchable supply-side resource.
- The RFP allows for creative responses which employ innovative or inventive technologies or processes.
- Resources must be considered firm capacity including firm deliverability into DEF.
- The RFP allows for both Tolling and Purchase Power arrangements.
- Existing and new capacity, including system power sales, are acceptable.
- In addition to their base proposal, Bidders may supply up to two variations (such as power augmentation, operating reliability impacts or financing terms) in project term and/or pricing at no additional cost.
- The DEF NPGU is a Combined Cycle with a capacity of 1,640 MW (summer) in Citrus County, FL.
- A minimum of 820 MW (summer) are required to be in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018.
- DEF will not accept external bid projects on DEF properties.
- Acceptable bid proposal must not exceed a maximum of 1,640 MW (net summer).
- DEF is seeking delivery terms in the range of 15 to 35 years.

DEF will utilize a Third Party Independent Monitor throughout the RFP process. Also, DEF will utilize Power Advocate as the web-base interface tool for posting and responding to the RFP. Power Advocate is a nationally recognized RFP web tool that is commonly used by Duke Energy ("DE") for various types and sizes of RFPs. All documents for this RFP will be maintained on Power Advocate's web site ("RFP web site'). DE will also provide a link from the Duke Energy RFP home page to the Power Advocate web site for this RFP as shown below. This DEF link will contain initial RFP documents and related bidder material prior to a bidder registering with Power Advocate. In addition, DEF reserves the right to post to the Power Advocate website written responses to questions from potential participants if DEF, in its sole discretion, deems it necessary to ensure that all potential participants have equal access to certain information.

DEF initial RFP information and link to Power Advocate RFP web site for RFP registration:

htpp://www.duke-energy.com/floridarfp

B. Objectives of the RFP

The purpose of the RFP is to solicit competitive proposals for supply-side alternatives to DEF's NPGU. DEF's intent is to select resources that offer the maximum value, based on price and non-price attributes, to the Company's customers. During its normal course of business, DEF regularly evaluates resource alternatives to fulfill its need for long-term system resources. As a result, DEF has identified as its NPGU the natural gas fired combined cycle resource generally described in Section IV of this RFP. DEF, however, reserves the right to cancel, modify or withdraw the RFP, to reject any or all responses, and to terminate negotiations at any time during the RFP process.

C. DEF's Year 2018 Resource Needs

DEF has a need for 1,640 MW (summer) in the year 2018, a minimum of 820 MW of which must be in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018. DEF's NPGU, subject to approval under the conditions specified in Rule 25-22.082 Florida Administrative Code, is the Citrus CC1, located in Citrus County Florida.

A detailed technical description, as well as the financial assumptions and parameters associated with the Citrus CC1, are provided in Section IV of this RFP.

D. Schedule

A schedule for critical dates for the solicitation, evaluation, screening of proposals, and subsequent negotiations follow:

A. Solicitation	
Pre-Release of RFP	9/24/2013
Pre-Release Meeting	10/2/2013
Issuance of RFP	**10/8/2013**
Bidders Meeting	10/18/2013
Submission of Proposals	**12/9/2013 by 3:00 pm**
B. Evaluation and Screening of Proposals	
Selection of Short List	Expected by 3/2014
Selection of Finalist(s)	**Expected by 5/2014**
C. Negotiations	
Initiate Negotiations	Expected by 5/2014
Clarifications and Adjustments	Expected by 6/2014
Award Announcement	Expected by 8/2014
D. Regulatory Filings	
File for certification	Expected by 9/2014

DEF reserves the right to revise the schedule at any time, at DEF's sole discretion. Depending on DEF's requirements to review the proposals, DEF may shorten or lengthen the schedule and revise the dates associated with the schedule.

The Pre-Release and Bidder meetings are scheduled for October 2 and October 18, respectively, at the Tampa Marriott Westshore, 1001 N Westshore Blvd, Tampa, Florida 33607 (1:00 – 3:00pm, each day in conference room Cotillion-Terrace).

E. Official Contact Persons

All inquiries or contact regarding this RFP, including questions of clarification and requests for additional information must be submitted to both the DEF RFP Contact and the Independent Monitor/Evaluator ("IM/E") Contact as listed below.

DEF RFP Contact and	**Independent Monitor/Evaluator Contact**
Benjamin Borsch	
Duke Energy Florida (DEF16)	Sedway Consulting, Inc.
299 1st Ave North	821 15th St,
St. Petersburg, FL 33701	Boulder, Colorado 80302
Telephone number: (727) 820-4781	Telephone number: (303) 581-4172
E-mail address:	E-mail address:
DEF2018RFP@duke-energy.com	Alan.Taylor@sedwayconsulting.com

Unsolicited contact with other DEF personnel or employees of DEF affiliated companies concerning the RFP is not allowed and will constitute grounds for disqualification. DEF reserves the right to provide written responses to all Bidders on the Power Advocate DEF 2018 RFP web site (www.duke-energy.com/floridarfp) if DEF, at its sole discretion, deems it necessary to ensure that all Bidders have equal access to certain information.

II. INFORMATION AND RESPONSIBILITIES FOR BIDDERS

A. General Instructions

Bidders to this RFP are required to meet all of the terms and conditions of the RFP to be eligible to compete in the solicitation process. In submitting their proposals, Bidders are required to follow all instructions contained in the RFP. Bidders must respond to all questions contained in the Response Package (Attachment C), use the provided Microsoft Excel schedules (Attachment D), organize their proposals according to the structure specified in the Response Package (*i.e.*, organized by chapter and section in the order specified by DEF), and provide supporting documentation in the format requested.

Bidders should include the Project Name, chapter and section numbers, and page number on each attachment. If a question is not applicable to the type of proposal submitted, Bidders should so indicate and specify why the requested information is not applicable to a particular proposal. This requirement is in place to assist the Bidders and DEF in assuring that no question has been overlooked and to provide all relevant information needed to evaluate the proposals. It is the Bidder's responsibility to advise DEF's Official Contacts of any conflicting requirements, omissions of information, or the need for clarification before bids are due. Bidders should clearly organize and identify all information submitted in their proposals to facilitate review and evaluation.

A Bidder's failure to provide all of the information for a proposal as requested in this solicitation process or to demonstrate that the proposal satisfies all of the Threshold Requirements and Minimum Technical Requirements identified in Section III will be grounds for disqualification.

Bidders should identify and clearly mark all confidential and proprietary information contained in its proposals as "Confidential". DEF and the IM/E will use its best efforts to protect the confidentiality of such information and only release such information on a need-to-know basis to the members of the RFP Project Team, management, agents and contractors, and, as necessary and consistent with applicable laws and regulations, to its affiliates and regulatory commissions. DEF's and the IM/E use of confidential information will be for the purpose of evaluating resource options for DEF. In no event shall DEF or the IM/E be liable to a Bidder for any damages of whatsoever kind resulting from DEF's or the IM/E failure to protect the confidentiality of the Bidder's information. By submitting a proposal, the Bidder agrees to allow

DEF and the IM/E to use all information provided and the results of the evaluation as evidence in any proceeding before the Florida Public Service Commission ("FPSC" or "Commission"). To the extent DEF and the IM/E wishes to use information before the FPSC that a Bidder considers confidential, DEF or the IM/E, as applicable, will request that the Commission treat such information as confidential and to limit its dissemination, but DEF and the IM/E cannot and will not make any assurance of the outcome of any such request.

All correspondence between potential Bidders and DEF must be through both the Official Contact Persons (DEF and IM/E) and all questions concerning this RFP must be submitted in writing. DEF will attempt to respond within a reasonable length of time to Bidders' requests and questions. Written responses, as determined appropriate by DEF, may be posted via the RFP web site. Potential bidders are responsible for periodically checking the DEF RFP website to see whether new questions and answers regarding the RFP have been posted.

B. Submission of Proposals

All proposals **must be received by DEF by 3:00 PM EST on December 9, 2013**. Proposals must be submitted to the DEF Official Contact through the Power Advocate web tool.

For each proposal, Bidders must submit a complete bid package consisting of all of the information required as described on the Power Advocate RFP web site for this DEF2018RFP by December 9, 2013. Additionally, a copied version of the submitted proposal in electronic format and provided on a flash-drive should be delivered to the IM/E at the Sedway Consulting address listed for the Official Contacts in Section I.E. no later than December 10, 2013.

The Response Package in Attachment C contains directions regarding the type and form of information Bidders are required to provide on the Power Advocate web site.

C. Proposal Fees/ Proposal Variations

Proposals Fees: Bidders may submit as many proposals as they desire. To help defray the cost of performing the proposal evaluations, including necessary internal DEF Transmission evaluations, Bidders are required to submit for each proposal a submittal fee of $20,000. All such submitted fees shall be non-refundable. The fee should be in the form of a check payable to "Duke Energy Florida, Inc." and delivered to the Official DEF Contact at the St. Petersburg address shown in I.E. no later than December 10, 2013.

Additional Federal Energy Regulatory Commission ("FERC") related Transmission Feasibility, Transmission Impact, and Transmission Facility Requests will follow related FERC Transmission processes and costs (see Section F below).

Variations: Bidders are allowed to propose up to a total of two variations (such as power augmentation, operating reliability impacts, commercial operation date, or financing terms) in project term and/or pricing at no additional cost. Bidders must submit a complete electronic version of the Response Package for each variation.

D. Proposal Terms and Conditions

As discussed above and provided within this document, DEF is seeking proposals for power supply resources to meet a need of 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. Consistent with DEF's need, the maximum size of proposal should be approximately 1,640 MW (summer).

Capacity and energy proposed to DEF under this proposal should be available no earlier than March 1, 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. The earliest contract end date for the delivery of capacity and energy should be May 1, 2033 (15 years). The latest contract end date for the delivery of capacity and energy to DEF should be May 1, 2053 (35 years).

Terms and Conditions ("T&C") are provided in Attachment A. As part of a Bidder's proposal, the Bidder shall provide comments (in electronically redlined form), to the T&C form(s) that is/are applicable to such Bidder's proposal(s).

E. Contract Flexibility Provisions

DEF is interested in creative responses that employ innovative or inventive technologies or processes that can meet the RFP requirements. Also, bidders are encouraged to offer contract flexibility provisions within their proposals. Possible provisions include, but are not limited to, contract term extension options in which bidders propose an initial contract term and provide DEF the option to extend the contract at predefined prices, options to terminate or buy out the contract, or options to shorten or terminate the contract in the event of any federal or state legislative or regulatory actions, including but not limited to amendments to the Florida Power Plant Siting Act, new North American Electric Reliability Corporation ("NERC") Standards or revisions to existing Standards, or new FRCC Standards or revisions to existing FRCC Standards that represent a material change to the contract or the electric utility industry in Florida. Within the context of any particular proposal, for the purpose of payment of proposal fees, as described in Section II.C, above, the offering of such flexibility provisions will not constitute another offer.

DEF has ongoing requests for power for Renewable and Qualifying Facility resources and suppliers who wish to offer such resources are encouraged to use this process at the following web site:

https://www.progress-energy.com/florida/home/renewable-energy/sell.page

F. Generator Interconnection Requests and Transmission System Analyses

DEF requires that all resources procured through the RFP process be deliverable via Firm Transmission Service to serve loads during the term of the agreement. Therefore, resources need to be either (a) located within and interconnected to DEF's transmission system, with any Generator interconnection facilities and/or transmission upgrades necessary to allow the resource to qualify as a designated network resource pursuant to the DEF Open Access Transmission Tariff ("OATT"), or (b) located outside DEF's system, with any interconnection facilities and/or transmission upgrades necessary to allow the resource to be deliverable to the DEF interface on a firm point-to-point basis as well as transmission upgrades necessary to allow the resource to qualify as a designated network resource pursuant to the DEF OATT.

As noted in Section II.E of the Response Package in Attachment C, Bidders who offer resources located outside of the DEF system will be responsible for coordinating with other transmission system owners, as appropriate, for securing firm point to point transmission service for delivery of the resource capacity and energy to the DEF system interface. If Bidders desire DEF to pay for any transmission-related costs, including interconnection, wheeling and upgrade costs of other transmission systems, then Bidders must include any such transmission-related costs in Schedule 1 (or Schedule 2, as applicable) of the Response Package.

As part of their submissions in response to this RFP, Bidders must complete the Transmission Information Schedule (Schedule 7 of the Response Package) and provide the data and information needed for DEF to conduct the analyses.

DEF 2018 RFP and DEF OATT Transmission bidder Information:

A summary of the procedures to be followed during the DEF 2018 RFP with respect to the DEF OATT bidder information is provided below. For reference, the DEF OATT can be accessed via the following internet link:

http://www.ferc.duke-energy.com/Joint_OATT.pdf

1. New Unit Proposals Inside the DEF System

a. Generator Interconnection Request

- New Unit Proposals physically located inside the DEF system will be required to submit a complete Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT in order to participate in the RFP. If site control is not demonstrated then an additional $10,000 deposit (non-refundable) is also required pursuant to the DEF OATT. Once DEF has reviewed the submitted application and deemed it complete, a generator queue position will be assigned and posted on the DEF Open Access Same-Time Information System ("OASIS").
- DEF plans to utilize the option within the DEF OATT LGIA process that allows DEF and the interconnection customer to delay the scheduling of the scoping meeting for the LGIA request. The provision will allow the LGIA queue request process to pause until such time as it is clear that the new unit proposal has been selected for the RFP short list. (See DEF OATT attachment J, 3.3.4.)

- If the bidder is selected for the short list, DEF will schedule the LGIA scoping meeting and the DEF OATT LGIA process will proceed forward. Additional studies and deposits are required and those will proceed sequentially pursuant to the DEF OATT. DEF will use the results of the previously completed RFP screening studies to the extent possible to defray the work (and cost) involved. The remainder of the OATT LGIA process requires an Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study with deposits of $10,000, $50,000 and $100,000 respectively. The deposits are intended to cover the actual study costs and any balances are refundable to the interconnection customer. If a New Unit Proposal falls out of contention for the RFP, DEF will consider the LGIA request as withdrawn and refund the deposit balance to the customer.
- Bidders of New Unit Proposals that will interconnect to DEF's system will be required to complete all forms and processes included in Schedule 7 of the Response Package.

2. All Other Proposals

- All other proposals (New Unit Proposals outside the DEF system, Existing Unit Proposals inside or outside the DEF system, and System Power Proposals) will be required to complete all forms and processes included in Schedule 7 of the Response Package. Bidders of New Unit Proposals to be located on another system will be required to complete all forms and processes included in Schedule 7 of the Response Package.

3. Transmission Service Requests

- Ultimately, DEF as the load serving entity is the DEF system transmission customer and will be responsible for making the formalized request(s) to designate the selected options as designated network resource(s) pursuant to the DEF OATT. The bidders themselves do not have to request transmission service on the DEF system for any of the types of proposals that are described in this document. DEF as the load serving entity will make the appropriate Transmission service request for DNR status for the option(s) that proceed to the RFP negotiation stage (See section I, item D above).
- The bidders are responsible for making requests for transmission service on other transmission systems as needed to obtain service to deliver to the DEF interface.

G. *Credit/Security Requirements*

DEF will require financial security to ensure the project is completed on schedule and is operated effectively and reliably.

The amount of security required from the seller is a function of the credit rating of the Seller, the structure of the capacity payments, and DEF's market exposure related to the agreement. In general, the amount required increases during the development of the facility and decreases during the term of the agreement, subject to variation based on future market conditions.

Security required for new projects to be developed is shown in the table below.

SECURITY SCHEDULE – NEW PROJECTS		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
12 months after contract signing	$20/kW	$60/kW
24 months after contract signing	$20/kW	$80/kW
Earlier of 36 months after contract signing or within 30 days after commercial operation	$20/kW	$100/kW [(a)]
10 years after c/o	($50/kW)	$50/kW [(a)]
15 years after c/o	($20/kW)	$30/kW [(a)]
During contract term, based on market exposure [(b)]	Up to $100/kW	Up to $200/kW

The following table shows the security required for existing facilities.

SECURITY SCHEDULE – EXISTING FACILITIES		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
Within 10 business days after beginning of term	$60/kW	$100/kW [(a)]
10 years after beginning of term	($50/kW)	$50/kW [(a)]
15 years after beginning of term	($20/kW)	$30/kW [(a)]
During contract term, based on market exposure [(b)]	Up to $100/kW	Up to $200/kW

Notes:

(a) Cumulative amount shown excludes the impact of any additional security required based on market exposure – see note (b).

(b) Additional security will be required in the event that DEF's market exposure exceeds the operational security that is otherwise required. DEF's market exposure represents the additional cost that would be required to replace the capacity and energy in the wholesale electric power markets or by constructing a new generation facility.

DEF will assign a Credit Limit to qualified Sellers based on the table below. In order to qualify for a Credit Limit, a Seller must maintain a credit rating from Standard & Poor's (S&P) or Moody's Investors Service (Moody's). A Seller may elect to provide a parent guarantee from a rated entity, in which case the assessment will be based on the guarantor's creditworthiness.

The Credit Limit will be calculated as a percentage of the Seller's Tangible Net Worth, subject to a maximum amount as shown under Credit Limit Cap. If the S&P and Moody's ratings are not equivalent, then the lower of the two will be used. The total required cash and letter of credit security as determined per above will be reduced by the Credit Limit amount as determined by reference to the table below. If at any time during the term of the agreement, the credit rating changes, then the amount of cash or letter of credit security will be adjusted accordingly.

Credit Rating from S&P / Moody's *	Percentage of TNW	Credit Limit Cap
A-/A3 or better	16%	$50,000,000
BBB+/Baa1	10%	$40,000,000
BBB/Baa2	10%	$30,000,000
BBB-/Baa3	8%	$30,000,000
Below BBB-	0%	$0

If during the term of the agreement DEF becomes entitled to terminate the agreement due to an event of default and if operation of the facility is not assumed by its lender(s) or its permitted assignee, then, in lieu of terminating the agreement, DEF will require the right to assume operational responsibility for the Facility to complete construction, continue operation, complete any necessary repairs, or take such other steps as are appropriate in the circumstances, or DEF may designate a third party or parties to do the same, so as to assure uninterrupted availability of capacity and deliverability of electric energy from the facility. Please see Section 3 of the T&C's in Attachment A for further explanation of DEF's rights upon default. (This provision will not apply to system sales.)

H. Permitting Responsibility

The Bidder(s) whose proposal is (are) selected will be responsible for acquiring in a timely fashion all necessary licenses, permits, certifications, and approvals required by federal, state and local government laws, regulations and policies for the design, construction, and operation of the project. In addition, the Bidder shall fully support all of DEF's regulatory requirements associated with this potential power supply arrangement. The Bidder is also completely and solely responsible for securing financing for its project. DEF shall have no responsibility in identifying or securing any licenses, permits, or regulatory approvals (other than being a co-applicant in a Determination of Need filing and a co-applicant in the Certificate of Need proceeding under the Florida Electric Power Plant Siting Act) or in securing any financing required for the construction or operation of the project.

I. Regulatory Provisions

Any negotiated contract between DEF and the Bidder will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the FPSC, Florida Department of Environmental Protection ("FDEP") and the FRCC. Any such negotiated contract will be further conditioned upon favorable regulatory action without substantial condition or qualification (including but not limited to temporal or other conditions or limitations on cost recovery) by any and all regulatory authorities from which regulatory approval may be required for the contract or for the development or effectuation of the power supply project and related activities (including but not limited to a Determination of Need by the FPSC).

For new unit proposals, in accordance with Rule 25-22.082 of the Florida Administrative Code, each participant [Bidder] is required

> … to publish a notice in a newspaper of general circulation in each county in which the participant proposes to build an electrical power plant. The notice shall be at least one-quarter of a page and shall be published no later than 10 days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the public utility that solicited proposals, and a general description of each proposed power plant and its location.

Bidders are required to upload electronic copies of these actual published notices to the DEF Power Advocate Website and email a copy to the IM/E within seven (7) days of the notice appearing in the newspaper. The copy of this notice shall clearly indicate the name of the newspaper and the date on which the notice was published.

J. Reservation of Rights

DEF reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. The Company also reserves the right in its sole discretion to decline to enter into a definitive, written agreement with any Bidder, or to abandon this RFP in its entirety. DEF reserves the right to revise the capacity need forecast at any point during the RFP process or during negotiations; any such change may reduce, eliminate, or increase the amount of power sought to be procured through this RFP.

Bidders should be aware that the following, without limitation, will be classified as non-responsive and may not be considered or evaluated if submitted:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- substantively incomplete, inaccurate, conditional, deceptive, misleading, ambiguous, exaggerated, or non-specific offers; or
- Proposals that are not in conformance with the requirements and instructions

contained herein.

Bidders that submit proposals do so without recourse against DEF or Duke Energy, Inc. or any of Duke Energy, Inc.'s subsidiary companies for either rejection of their proposal(s) or for failure to execute a definitive, written agreement for any reason.

III. DEF 2018 RFP PROCESS

The solicitation process is a multi-phase process consisting of four general phases and several sub-phases or steps. This Section III of the RFP describes the process in detail and outlines Bidder requirements and alternatives for each phase and step of the process.

DEF will also utilize Sedway Consulting, Inc as an independent monitor throughout the RFP process, including the Evaluation and Screening Process.

This Section III of the RFP is organized chronologically according to the sequence of steps in DEF's solicitation process. Specifically, the areas to be discussed are the (A) Solicitation activities, (B) Evaluation and Screening process, (C) Negotiations, and (D) Regulatory Process. Discussed as part of the evaluation process are the minimum requirements that all proposals must meet as well as the evaluation criteria that will be used to identify the most attractive proposals.

A. Solicitation

The solicitation activities phase of the process includes the period from issuance of the RFP to the submission of proposals by Bidders.

1. Notice of Intent to Bid and RFP Registration

Bidders are asked to submit a courtesy Notice of Intent to Bid ("NOI Form") in order to assist DEF in preparing for the Pre-Issuance meeting, the Bidders meeting, and the RFP process. Bidders are encouraged (but not required) to submit the NOI Form by October 2, 2013. Submitting a NOI Form does not commit a prospective Bidder to submitting a proposal to DEF.

Please submit an electronic copy of the NOI via the Power Advocate RFP web site or to the DEF RFP Official Contacts by email.

The NOI Form along with Power Advocate registration instructions are provided at the following website:

htpp://www.duke-energy.com/floridarfp

2. Pre-Release and Bidders Meetings

Pre-Release Meeting:

DEF will conduct a Pre-Release Meeting for interested potential Participants on October 2, 2013 at 1:00 PM at the Tampa Marriott Westshore, 1001 N. Westshore Blvd, Tampa, Florida 33607. If this time or location changes, DEF will provide notice on the RFP website. The purpose of the Pre-Release Meeting is to allow interested potential participants the opportunity to ask questions and seek additional information or clarification about the solicitation process. **To make the meeting as productive and informative as possible, Bidders are encouraged to submit a written list of questions concerning this RFP to the DEF RFP Official Contacts prior to October 2, 2013.**

Bidders Meetings:

DEF will conduct a Bidders Meeting for interested Bidders **on October 18, 2013** at 1:00 PM at the Tampa Marriott Westshore, 1001 N. Westshore Blvd, Tampa, Florida 33607. If this time or location changes, DEF will provide notice on the RFP website. The purpose of the Bidders Meeting is to allow interested Bidders the opportunity to ask questions and seek additional information or clarification about the solicitation process. **To make the meeting as productive and informative as possible, Bidders are encouraged to submit a written list of questions concerning this RFP to the DEF RFP Official Contacts prior to October 18, 2013.**

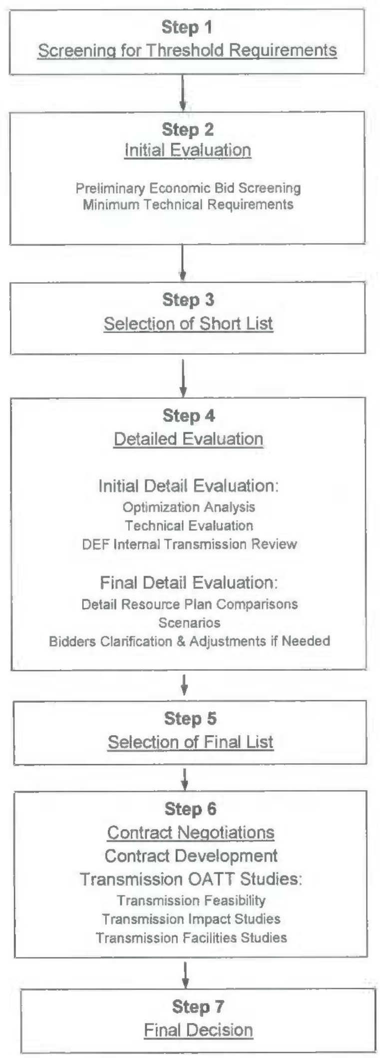
3. Submission of Proposals

The last step during this phase of the process is the submission of proposals. As noted, all proposals **must be received By the DEF Power Advocate web tool by 3:00 PM EST on December 9, 2013**. Additionally, a copied version of the submitted proposal in electronic format and provided on a flash-drive should be delivered to the IM/E at the Sedway Consulting address listed for the Official Contacts in Section I.E. no later than December 10, 2013. Proposals must remain valid for acceptance by DEF until DEF either (i) releases a proposal (by DEF informing the Bidder that its proposal was not approved to proceed to a next step in the evaluation process), (ii) accepts the proposal, or (iii) negotiates different terms during the Negotiation phase, whichever is earlier. **Failure to submit the proposal by the specified time will be grounds for disqualification.**

B. Evaluation Process

DEF will use a seven-step evaluation and screening process to review proposals and to select the best alternative. Figure III-1 illustrates the evaluation process, starting with the receipt of proposals to the final decision. The evaluation process is described more fully below.

FIGURE III-1
Evaluation Process



1. Step 1: Screening for Threshold Requirements

Subsequent to the receipt of the Bidders' proposals, DEF will thoroughly review and assess each proposal to ensure that it meets the Threshold Requirements listed in the RFP. Threshold Requirements represent the minimum requirements that all proposals are required to meet and with which a Bidder's compliance can be easily assessed. DEF may, at its sole discretion, seek clarification and/or modification of a Bidder's proposal at this stage of the evaluation process. Each Bidder should ensure that a contact person is available to DEF and Sedway Consulting throughout the Evaluation Process.

DEF views Threshold Requirements to be an important aspect of the evaluation process. The Bidder should ensure that its proposal satisfies the Threshold Requirements listed in FIGURE III-2 to be eligible for further consideration in the evaluation process. Bidders should also review and provide comments to the Key Terms & Conditions in Attachment A, because they are the terms and conditions that will be used to evaluate the Bidder's conformance with certain Threshold Requirements in this RFP. The information Bidders are required to provide to demonstrate their compliance with the Threshold Requirements is specified in greater detail in the Response Package.

Bidders must ensure that their proposals contain sufficient documentation to demonstrate that they meet all Threshold Requirements. **Failure to conform to the Threshold Requirements will be grounds for disqualification.** Proposals that are disqualified will not be evaluated further.

FIGURE III-2
Threshold Requirements

A. **General Requirements**
- The proposal is received on time.
- The proposal submittal fee is received by DEF.
- The pricing schedules are properly specified and the proper price indices are used.
- Power must be available for delivery under the contract May 1, 2018
- The proposed contract end date is no earlier than April 30, 2033

B. **Operating Performance Thresholds**
- If the project is located in DEF's system, the Bidder's proposal will be required to show documentation that the following operational criteria can be meet:
  - to operate the project to conform with DEF's ***Voltage Control*** requirements.
  - to operate the project to conform with DEF's ***Frequency Control*** requirements.
  - to be ***Fully Dispatchable*** and install ***Automatic Generator Control*** ("AGC") that is tied into DEF's Energy Control Center **[New and Existing Unit Proposals]**.
- If the project is located outside of DEF's system, New and Existing Unit Proposals must provide documentation to show that the proposal is ***Fully Dispatchable*** and provide ***Dynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.
- The Bidder must show documentation they are willing to ***coordinate the project's maintenance scheduling*** with DEF.
- System Power Proposals must show documentation that the proposal is ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). System Power Proposals must also provide D***ynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.

C. **Terms & Conditions Thresholds**
- Bidders must agree to each of the Terms & Conditions identified in Attachment A.
  - OR -
- If Bidder has any objections to the Terms & Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

D. **Site Control Thresholds [New and Existing Unit Proposals]**
- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title (or long term lease) and legal description of the property is required for **Existing Unit Proposals**.

E. **Transmission Threshold**
- If the proposal is for resources located outside of DEF's system, the Bidder must provide a transmission plan that exclusively utilizes firm transmission service from the host system to the DEF system. Bidders must provide evidence that the host system is willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals. Bidders must provide host utility documentation that the results of a generator feasibility study and/or a host transmission system impact study performed by the host system will be completed or documentation such as a transmission study agreement showing that the results will be available no later than 30 days following the bid submittal date.
- For New Unit Proposals physically located inside the DEF system, documentation that the required Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT has been submitted to DEF **[New Unit Proposals]**.
- The Transmission Information Schedule (Schedule 7 of the Response Package) is properly completed for **All Proposals**.

2. Step 2: Initial Evaluations

Generation Economic Screening:

In the preliminary economic screening evaluation, DEF will evaluate each proposal based on its proposed prices. DEF's pricing parameters for New and Existing Unit Proposals are specified in the Response Package. The requirements for pricing bids for System Power Proposals are also specified in the Response Package. See Figure III-3 for additional pricing parameters.

FIGURE III-3
New and Existing Unit Proposal Pricing Parameters

Fixed Payment	• The monthly fixed payment to Bidders will be based on the product of the Seasonal Contract Capacity, one-twelfth (1/12) of the Bidder-specified annual charges (the possible components of which are detailed below). • Bidders must complete the applicable Pricing Schedules in the Response Package • If Bidders desire, they may propose alternative methods of distributing annual payments on a monthly basis.
Generation Capital Component	• Bidders must specify a generation capital charge for each year of the proposal.
Transmission Component	• Bidders must specify a transmission charge for each year of the proposal. • This charge must include all interconnection and, if applicable, wheeling costs, and upgrade costs of other transmission systems required for delivery of Firm Power to the DEF system. • During the Initial Evaluation (Step 3) and the Detailed Evaluation of proposals (Step 5), DEF will estimate transmission system upgrade costs for the DEF system and other affected systems needed to integrate the proposed power into the DEF transmission network. • The Bidders' transmission charge and DEF's estimate of any additional transmission system upgrade costs will be included in DEF's economic evaluation.
Fixed O&M Component	• Bidders must specify annual fixed O&M charges for each year of the proposal.
Fixed Pipeline Demand / Reservation Component	• Bidders must specify a fixed pipeline demand/reservation charge (if appropriate to the technology being proposed). Bidders must specify a charge for each year of the proposal. • Bidders may propose a fuel transportation tariff as the price. • DEF reserves the right to negotiate fuel transportation provisions with the Bidder if benefits can be derived for DEF and its customers.
Variable Payment	▪ The variable payment to Bidders will be based on the following components: fuel price and variable O&M price components. ▪ Bidders must complete the applicable Pricing Schedules in the Response Package.
Fuel Price Component	Bidders must specify commodity prices and variable transportation prices for the primary (and, if appropriate, secondary) fuels. Bidders have three options for proposing fuel prices: 1. the Bidder may specify a series of firm prices or a price that escalates at a Bidder-specified rate. These prices will be used for evaluation and payment purposes. 2. the Bidder may propose to use a price index or propose a formula based on an index. 3. the Bidder may propose to use a fuel tolling arrangement whereby DEF will supply fuel tolling services to the project. If the Bidder selects this option, DEF will determine the appropriate price to use for the evaluation. • Formulas and escalation rates, if used, must be specified by the Bidder • DEF will not allow Bidders to merely state that fuel is a pass-through. DEF may allow a pass-through as a result of the negotiation process and, as a condition for this, would reserve the right to participate in the management of the project's fuel supply, but reserves the right to accept the base price and index or fixed escalation rate specified by the Bidder.

		• Bidders must specify the months in which the primary (and, if appropriate, secondary) fuels will be expected to be used and be prepared to be evaluated and paid on that basis.
	Variable O&M Component	• Bidders should specify in Schedule 1 annual variable O&M prices for each year of the proposal. Variable O&M may be stated in $/MWh, $/hour, or both.
Start Payment Component		• Bidders should specify annual start prices for each year of the proposal. Start payments will be paid only for those starts actually exercised by DEF. The cost to start the Facility for test starts, following a forced outage, or after unplanned maintenance will not be included in DEF's payments to the Bidder.

In the preliminary economic screening, DEF will use a spreadsheet model to compare the costs of each proposal to the other proposals at an appropriate capacity factor(s) as needed to evaluate the competitive rankings of each proposal. Such capacity factors may include, but are not limited to, capacity factors based on the anticipated dispatch of the resource within the DEF system of resources for the proposal. **DEF reserves the right to use the preliminary economic screening to eliminate proposals with high costs (relative to other proposals) from consideration without performing further analyses.**

Minimum Technical Criteria Evaluation:

Proposals will be evaluated on an initial technical basis to assess the feasibility and viability of each proposal. As part of this Minimum Technical Evaluation, proposals will be reviewed to ensure that they conform to the Minimum Technical Requirements described below.

i. Minimum Technical Requirements

DEF will apply Minimum Technical Requirements as a step in the initial evaluation process. These Minimum Technical Requirements, identified in Table III-4, are the technical "must have" elements of a proposal. The information Bidders are required to provide to demonstrate their compliance with these Minimum Technical Requirements is specified in greater detail in the Response Package. Each Minimum Technical Requirement will be evaluated on a "Pass/Fail" or "Go/No Go" basis.

Bidders must ensure that their proposals contain sufficient documentation to demonstrate that they meet all the Minimum Technical Requirements. **Failure to demonstrate conformance to these Minimum Technical Requirements will be grounds for disqualification.**

FIGURE III-4
Minimum Technical Requirements

A. **Environmental**
- * Preliminary environmental analysis performed and submitted to DEF [New Unit Proposals].
- * Reasonable schedule for securing permits presented with evidence provided that it is reasonable to expect that permits can be secured in a timely fashion [New Unit Proposals].

B. **Engineering and Design**
- * The project technology is capable of achieving the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].
- * Operation and Maintenance Plan provided that indicates the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. **Fuel Supply and Transportation Plan**
- * Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. **Project Financial Viability**
- * For New Unit Proposals, evidence provided that it is reasonable to expect that the project is financially viable (assuming a power purchase agreement is in place with DEF) [New Unit Proposals].
- * Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. **Project Management Plan**
- * For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial within the time frame requirements of this RFP [New Unit Proposals].

Generator Interconnection and Transmission Integrated Screening

For New and Existing Unit Proposals inside the DEF system, the Transmission Screening study will consist of a power flow analysis by the Transmission Group. For proposals in which the project is not interconnected with the DEF transmission system, preliminary transfer analyses will be performed to examine the impact on the DEF transmission system of a transfer from the host system of the project to the DEF system.

The transmission screening study will assess the impacts to the DEF transmission system and will result in a list of transmission facilities, and an estimate of the cost of the facilities.

Preliminary Total Cost Generation and Transmission Economic Screening

The combined screening results of the Generation, Interconnection and Transmission Integration costs provide the input to develop a total cost review and analysis for developing a mix of resources for Step 3 below.

3. Step 3: Selection of Short List

DEF's objective is to select a Short List of proposals which includes a mix of proposals that make up the best resources to allow further review as a system resource plan. Those proposals which are substantially inferior to other proposals will be eliminated from further consideration. DEF reserves the right to select as many proposals as needed for the Short List to develop reasonable resource plans for system evaluations, as DEF deems appropriate in its sole discretion. DEF will notify all short-listed Bidders that they have been selected for the Short List.

4. Step 4: Detailed Evaluation

Proposals that are included on the Short List will be subjected to a more detailed assessment and will be compared to DEF's self-build alternative. Consistent with Florida PSC rules, DEF encourages participants to formulate creative responses to the RFP. Without knowing the details of the proposals that may be submitted, DEF is not able to identify or describe all the detailed analyses that may be needed to determine which alternative is the most cost-effective alternative.

The Detailed Evaluation will consist of the Initial Detailed Evaluation followed by a Final Detailed Evaluation as follows:

Initial Detailed Evaluation

The next phase of the evaluation process is the Initialed Detailed Evaluation of proposals. In this step, the estimated costs from the initial screening study for the short list Bidders' proposals will be converted to Initial Resource Plans for further evaluations.

The Initial Detailed Evaluation will consist of several analyses conducted in parallel:

a. Optimization Analyses,
b. Technical Criteria Evaluation, and
c. Transmission Reviews.

a. Optimization Analyses

In the Optimization Analyses, DEF will analyze each short list bidder proposal's value by developing an optimal resource plan around each proposal and determining the cumulative present value of revenue requirements ("CPVRR") of the plan developed around the particular proposal. The Strategist optimization model will be used to develop the optimal plans and DEF will assess the impacts of each proposal on system costs over DEF's planning horizon. Generic combustion turbine and combined cycle plants will be available technologies from which the optimization model can select to develop the optimal plans. Depending on the nature of the proposals received, DEF may also examine combinations of proposals in the development of the portfolios which will be screened to identify optimal resource plans. Proposals with different capacity duration terms will be backfilled by the available generic resource technologies. The economic impact of the resource plans will be evaluated for both transmission and generation. For the generation portion, the production costs will be calculated using Energy Portfolio Management ("EPM") our detailed production cost tool. The Transmission Analyses will provide Transmission Capital Costs. The value of the proposal will be the CPVRR for its portfolio and will include Generation and Transmission Capital Revenue Requirements and Production Costs.

b. Technical Criteria

Technical Criteria are characteristics (non-price attributes) DEF desires that will increase the relative attractiveness of proposals that otherwise meet the Minimum Technical Requirements. DEF will use three major attributes to evaluate proposals' Technical Criteria: (1) expected operational quality; (2) expected development and commercial feasibility; and (3) estimated project value (non-price). Each of the evaluation criteria that are contained within these evaluation attributes are identified in FIGURE III-5 and discussed below. Proposals will be ranked relative to each other for each of the Technical Criteria.

Bidders will need to include information in their proposals that will support the Bidder's statements with respect to these technical criteria. Further, Bidders should assume that there will be provisions in any definitive, written agreement that DEF signs that reinforce the representations made by the Bidder with respect to these Technical Criteria. **Inability of a Bidder to adequately substantiate the basis for any representation will be grounds for a downward revision of its proposal's ranking or, in the event of misrepresentation, disqualification from this bidding process.**

FIGURE III-5
Technical Criteria

Operational Quality	Development and Commercial Feasibility	Project Value (non-price)
♦ Minimum Load (N, E)	♦ Permitting Certainty (N)	♦ Acceptance of Key Terms and Conditions (N,E,S)
♦ Start Time (N, E)	♦ Financial Viability of the Project (N)	♦ Fuel Supply and Transportation Plans (N,E,S)
♦ Ramp Rate (N, E)	♦ Credit Quality of Bidder (N,E,S)	♦ Generation Reliability Impact (N,E,S)
♦ Maximum Allowable Starts per Year (N, E)	♦ Commercial Operation Date Certainty (N)	♦ Unit Reliability Practices (N,E,S)
♦ Minimum Run-Time Constraint (N, E)	♦ Bidder Experience (N,E,S)	♦ Flexibility Provisions (N,E,S)
♦ Minimum Down-Time Constraint (N, E)		
♦ Annual Operating Hour Limit (N, E)		

N = New Unit Proposals, E = Existing Unit Proposals, S = System Power Proposals

Operational Quality

There are seven evaluation criteria that are considered as part of the operational quality attribute: (1) minimum load; (2) start time; (3) ramp rate; (4) maximum allowable starts per year; (5) minimum run-time constraint; (6) minimum down-time constraint, and (7) annual operating hour limit. DEF will expect that any definitive, written agreement for New and Existing Unit Proposals will include provisions requiring tests to be conducted periodically during the contract term to ensure that the Bidder's project conforms to the start time and ramp rate operating parameters claimed in its proposal. Failure to conform to these operating parameters will subject Bidders to performance penalties under any definitive, written agreement with DEF entered into as a result of this RFP.

The minimum load is the lowest capacity level at which the project may be continuously operated. DEF prefers projects that show flexibility by allowing operation at less than full load. The minimum loading level while on AGC should also be provided if different from plant local operation.

Start time assesses the amount of notice required to bring the unit, under normal operations, from a cold start to minimum synchronized load. DEF prefers proposals that have short start times.

Ramp rate assesses the megawatt (MW) increase per minute that can be provided by the project once the unit is at or above the minimum loading level. DEF prefers proposals that offer a high ramp rate. The ramp rate while on AGC should also be provided if different from plant local operation.

A maximum start per year assesses the maximum number of times that DEF will be allowed to start the Bidder's project. Test starts, starts after a forced outage, and starts after unplanned maintenance will not be included when determining the number of starts requested by DEF. DEF prefers proposals in which there is no limit on the number of times that DEF can start a project.

Minimum run-time constraint assesses the number of hours that the project is required to be operated at or above its minimum operating level once it has been dispatched on line. DEF prefers proposals that have no minimum run-time constraints.

The minimum down-time constraint assesses the number of hours that the project is required to remain out of service once it has been taken off-line for economic dispatch, maintenance outage, or forced outage. DEF prefers proposals that have no minimum down time constraints.

The annual operating hour limit assesses the number of hours during a year that DEF would be allowed to operate the Facility. DEF prefers proposals that have no operating hour limits.

Development and Commercial Feasibility

There are five evaluation criteria that are considered as part of the development and commercial feasibility attribute: (1) permitting certainty; (2) financial viability of the project; (3) Bidder credit quality; (4) commercial operation date certainty; and (5) Bidder experience. All five of these evaluation criteria will be considered for New Unit Proposals. Existing Unit and System Power Proposals will be evaluated based on two criteria: the Bidder's credit quality and Bidder experience.

The permitting certainty evaluation criterion assesses the degree to which the Bidder is able to demonstrate that it has identified and can secure all of the required major permits, approvals, certificates, and licenses within the period indicated on the project's critical path schedule. Relative to other proposals, DEF prefers proposals that provide well-conceived plans for securing all required permits, approvals, etc., demonstrate a thorough understanding of the permitting process, have realistic permitting and approval schedules, and have made greater progress in securing permits and approvals.

The project financial viability evaluation criterion assesses the financial viability of the Bidder's proposal, while Bidder's credit quality assesses the financial capability and credit of the Bidder. For New Unit proposals for which the Bidder is proposing to obtain project financing for its proposal, DEF's evaluation will focus on the financial viability of the proposal, and will evaluate project pro-forma financial statements based on the assumptions and capital structure in the proposal. To show financial viability, the Bidder needs to demonstrate that the project is, or eventually becomes, free cash flow positive (not every year must show positive free cash flows but, in general, the project should be positive more than it is negative). There is no specific cash flow hurdle. If the Bidder indicates that it will be providing equity to the project or will self-finance the project, DEF will also assess the Bidder's ability to provide the required equity or financing through the credit review. For New Unit Proposals, DEF prefers proposals for which the Bidder is able to demonstrate that there is a high likelihood of the project securing financing. For System Power and Existing Unit Proposals, DEF's evaluation will focus on the financial resources and credit quality of the Bidder.

DEF will also evaluate the Bidders' creditworthiness to assess the Bidders' financial ability to fulfill their obligations to DEF over the term of the contract.

DEF will require credit support as described in section II.G.If a respondent plans on providing a parent guarantee, and then financial information for the guarantor should be provided.

Commercial operation date certainty assesses the degree to which the Bidder is able to demonstrate that it will be able to bring the project to commercial operation of approximately 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. For New Unit Proposals, DEF will evaluate the reasonableness of the following aspects of the Bidder's proposed schedule: permitting and approvals, fuel supply and transportation arrangements, construction or upgrades of necessary transmission facilities, engineering design, project financing, equipment procurement, project construction, and start-up and testing. DEF evaluation will consider the evidence presented by the Bidder that the proposed schedule for each of these project elements is achievable. DEF prefers proposals for which the Bidder is able to demonstrate that there is a reasonable likelihood that the project will be able to achieve the commercial operation date requirement. DEF will expect that any definitive, written agreement it signs for a proposal resulting from this RFP will include penalty provisions for delays in the commercial operating date.

Bidder experience assesses the relative experience of the Bidder in developing and operating projects that are of an equivalent size and technology as the Bidder proposes in response to this RFP. For a New Unit Proposal, DEF will evaluate the Bidder's relevant experience in six areas: permitting and approvals, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. DEF prefers Bidders that have a history of successfully developing comparable projects. For proposals that rely on project teams composed of more than one firm to develop the projects, DEF prefers project teams that have a history of working together to successfully complete projects. DEF will review the Unit Reliability Program as the relative strength of the proposal to maintain operation at full capacity. DEF will evaluate the Bidder's plan for performing operations and maintenance including proposed O&M spending, planned engagement of an Long-Term Service Agreement ("LTSA"), allowance for capital spares, levels of redundancy in Balance of Plant ("BOP") equipment, major equipment technology selections and any unit identified restrictions. DEF prefers proposals that identify robust maintenance programs. DEF will consider Bidders demonstrated history of reliable operations for unit proposals in this response and other units operated by the Bidder. For a Bidder that proposes to supply DEF's capacity requirements from existing capacity, DEF will only evaluate the Bidder's fuel procurement and operations and maintenance experience. DEF will also examine the litigation history of all Bidders.

Project Value (Non-Price)

The project value (non-price) attribute considers the following four evaluation criteria: (1) the Bidder's degree of acceptance of the Terms & Conditions provided in Attachment A; (2) the reliability of the Bidder's fuel supply and transportation plan; (3) the impact of the proposed project on DEF's generation system reliability; (4) any flexibility provisions proposed by the Bidder.

Attachment A to this Solicitation Document contains Key Terms & Conditions, which will be used as the basis for this RFP and any possible negotiations of any final definitive, written agreement between DEF and one or more Bidders. DEF will evaluate the Bidder's acceptance of the Key Terms & Conditions by assessing the degree to which exceptions identified by the Bidder shift risk from the Bidder to DEF or its customers. DEF prefers Bidders which request no changes to the Terms & Conditions or which request only minor changes that have no material effect on the allocation of risk within any contract ultimately executed.

DEF will evaluate the reliability of the Bidder's fuel supply and transportation plans by assessing the status of its fuel supply and transportation arrangements, the strength of the proposed fuel supplier (and fuel transportation options), and the relative risk of (or flexibility among) the Bidder's proposed fuel supply and transportation arrangements. DEF prefers proposals that have well developed fuel supply and transportation arrangements, rely on a major fuel supplier that offers a diverse mix of potential fuel supplies and access to a number of different transportation alternatives, and have minimal fuel supply and transportation risks.

DEF will evaluate the impact on generation system reliability of the project proposed by Bidders, primarily through an examination of outage rate information provided by the Bidder. Depending on the proposals received, additional analyses may be required. DEF prefers bids that provide high levels of reliability – defined in terms of level of availability (tied to planned and unplanned outage rates). It is expected that unit-contingent proposals will have availability rates less than 100%. However, Bidders of System Power Proposals must guarantee 100% availability for the capacity and energy offered to DEF. Should curtailments be necessary for System Power Proposals, DEF prefers proposals that curtail delivery only on a pro-rata basis simultaneously and proportionately along with the Bidder's other firm sales, including primary public service obligations.

DEF reserves the right to take into consideration any unique flexibility provisions offered by a Bidder that are not considered elsewhere, such as in the economic evaluation. DEF favors bids which provide flexibility for meeting its projected requirements. DEF will finalize the Technical Criteria Evaluation of the short-listed proposals, after seeking clarification on any outstanding issues that resulted from the Technical Criteria Evaluation in the Initial Detailed Evaluation.

DEF will finalize the Technical Criteria Evaluation of the short-listed proposals, after seeking clarification, as DEF deems necessary, on any outstanding issues that resulted from the Technical Criteria Evaluation in the Initial Detailed Evaluation.

c. Transmission Reviews

DEF will incorporate the results of the Transmission Screening Study along with the preliminary information from the generation optimization and technical review, to assess the feasibility of the proposals that could be combined to form a preliminary Transmission Group for the DEF transmission system. A Transmission Group could be a single or multiple RFP proposals that would be studied together for overall transmission impact to the Bulk Electric System (BES).

In the initial detailed evaluation phase, DEF may perform detailed transmission cost estimates as well as an estimate of the time to construct the required facilities for each Transmission Group. If in DEF's judgment, the transmission cost estimates are determined to be a decisive factor in the overall Final Detailed Evaluation, then detailed transmission cost estimates will be performed. A detailed transmission cost estimate would go beyond previous cost estimates to more closely represent the actual cost expected of the Transmission Group.

In evaluating alternative proposals, DEF will include the costs of any necessary transmission network upgrades necessary to deliver the output of the new generator and/or power transfers from existing generation sources to DEF load. If the Response Package includes costs on other third party systems then those costs will be included in the evaluation.

The transmission network upgrade costs are based on all modifications (new facilities and facility upgrades) to the DEF transmission system that are necessary to physically transfer the proposed power from the DEF system receipt point to the load center consistent with reliability standards for 2018 Summer and 2018/19 Winter conditions. The latest available Florida Reliability Coordinating Council ("FRCC") peak load flow case (updated as necessary to reflect the latest available information) will be used as the basis for determining the transmission network upgrade modifications needed. Once these modifications are determined, costs for these modifications will be estimated and assigned to the appropriate Transmission Group.

The process of determining the needed transmission network upgrade modifications generally consists of two steps as follows:

Step One - The transmission studies performed to determine the deliverability of the various proposals to DEF load will be considered screening type studies and will not be as comprehensive as studies done for a request for service pursuant to DEF's OATT. The transmission screening studies will be sufficient to provide reasonable estimates of the transmission impacts to integrate the proposals into the DEF system and will involve the same reliability criteria for comparison purposes. The transmission service studies will be done consistent with NERC, FRCC and DEF standards to insure that DEF can serve its customers and meet its transmission service obligations in the years 2018 and beyond. Each of the Transmission Groups will be subjected to contingency screening of all transmission elements and generators, and the transmission system is monitored for violations of NERC, FRCC, and DEF standards. Contingency screening tests will be performed at Summer and Winter peak load conditions with all DEF generators/facilities assumed available and economically dispatched. Further, the generator deemed most critical to each Transmission Group will be assumed to be unavailable and the remaining DEF generators dispatched to mitigate if practicable, violation of reliability criteria for all contingencies tested. Violations of reliability criteria found on the DEF system are resolved by acceptable remedial action (e.g., switching), facility upgrades, or by new facilities, as appropriate.

All proposed solutions will be subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution. If the transmission reviews reveal that a Transmission Group causes a potential violation on a third party affected system that was not identified in the response package, DEF will inform the Bidder(s) that they must communicate with the operator of the affected system and provide estimates of the attendant cost of resolving the violation. It is possible that a potential violation could be attributable in part to the Transmission Group being evaluated and would require a coordinated effort of multiple parties.

Step 2 - Once a list of network upgrades on the DEF system required for integration is identified, the second step of the transmission review evaluation process is developing cost estimates for the new and upgraded transmission facilities. Based on the need for incremental transmission network upgrades identified in each Transmission Group, a cost estimate for the facilities is developed in a consistent manner for each Transmission Group. The estimates will be based on engineering judgment and readily available cost information, including cost information previously obtained from third party entities and equipment manufacturers for transmission reinforcements of the type and capacity required for each portfolio.

Summary of Initial Detailed Evaluation

DEF will combine the three steps, (a) the Optimization Analyses, (b) Technical Criteria Evaluation and (c) the Transmission Reviews, for a combined review of initial competing alternative plans against the self-build alternative. Adjustment may be necessary to further optimize the Resource Plans when the combined results are reviewed.

Final Detailed Evaluation

DEF will further review the short list bidder proposals that satisfy the Initial Detailed Evaluation in a robust review of competing alternative plans against the self-build alternative. DEF plans to use EPM and a detailed financial model to further compare the short-listed proposals to DEF's self-build alternative. Using the optimal plans for the short listed proposals developed in the initial evaluation, the final evaluation will assess the impact of each alternative on the CPVRR over the planning horizon compared to a Base Case plan.

In order to treat all alternatives the same in the economic analysis, all cases will be compared to a Base Case optimal plan. The results of the production costing analyses will be incorporated into the detailed financial analysis of each alternative. In addition to the direct costs associated with each alternative (that is, the energy charges of the proposals and the operating costs of the self-build alternative), the change in system production costs compared to the Base Case will also be a part of the financial analysis. The fixed costs associated with each alternative (the fixed charges of the proposals and the construction costs and fixed O&M of the self-build alternative) will be included in the analysis as an add-on to the production costs. The cost impacts of the changes in the resource plan will be reflected in the financial analysis through charges or credits representing the revenue requirements of units added, accelerated, or deferred.

DEF will apply the cost of imputed debt to Bidders' proposals to assure that the total costs of proposals include the marginal impact of the fixed future commitment on DEF's capital structure. The annual additional equity cost of imputed debt on a revenue requirements basis is calculated as:

Annual Additional Equity Cost =
Risk Factor * Present Value of Future Fixed Payments
* (Cost of Equity Rate – After Tax Cost of Debt Rate)
* Equity Ratio / (1 – Tax Rate)

where the Risk Factor and Present Value of Future Fixed Payments are calculated consistent with the S&P Standard Methodology.

This additional cost is the direct result of having the transaction cause DEF to incur fixed future payment obligations. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments. The Risk Factor is the percentage of the future fixed payments to be added to balance sheet debt and depends on a number of factors, including the conditions of a purchased power proposal, counterparty risk, and regulatory cost recovery risk. The biggest factor in selecting a risk factor is the degree of certainty and timeliness of regulatory recovery by the utility. Based on Standard & Poor's recommendation, utilities in supportive regulatory jurisdictions with a regulatory precedent for timely and full cost recovery of fuel and purchased-power costs, may use a risk factor as low as 25%.

Based on the team's review of the proposals submitted, DEF may deem it appropriate to perform scenario analyses (e.g., to examine flexibility options proposed by a Bidder), sensitivity analyses of key costs and performance characteristics (such as, but not limited to, heat rate, outage rate, construction cost, O&M costs, and energy costs), and/or any other type of analysis that DEF deems appropriate.

DEF may elect to schedule meetings or conference calls with each short-listed Bidder to review and clarify its proposal. DEF reserves the right to seek clarification or additional information from each Bidder regarding its proposal and develop appropriate adjustment in order to thoroughly evaluate a proposal.

5. Step 5: Selection of Final List

DEF may develop a Final List based on the detailed evaluation of the short-listed proposals. This Final List will not necessarily be composed of the lowest cost proposals since the combination of price and non-price terms may provide greater value to customers than the lowest cost proposals. DEF will exercise professional judgment in performing the analyses and in making the final selection of the RFP process. DEF's objective is to select resources that offer the maximum value, based on price and non-price attributes, to the Company and its customers. The final-listed Bidders will be those Bidders with which DEF will begin contract negotiations.

DEF will not necessarily put any Bidder proposals on the Final List. In the event DEF's self-build alternative is superior to the short-listed proposals, a Final List will not be selected and an appropriate announcement will be made.

6. Step 6: Negotiations and Transmission Facilities Studies

Immediately after the Final List announcement, DEF will begin negotiations with Bidders on the Final List. As previously noted, DEF has included T&C in the RFP to allow Bidders to identify their exceptions, thereby expediting negotiations and allowing DEF to assess the significance of the changes requested by Bidders. Inclusion of a proposal in the Final List does not indicate DEF's acceptance of the exceptions identified by the Bidder. DEF reserves the right to negotiate any terms and conditions which provide value to DEF and its customers. Also, if in DEF's view the negotiations are not proceeding on a reasonable schedule to ensure achievement of the in-service date requirement, DEF has the right to terminate negotiations with that Bidder.

7. Step 7: Final Decision

DEF will make its final decision related to this RFP once all definitive, written agreements have been fully negotiated and are ready to be executed by the parties, and any required Interconnection and Transmission Facilities Studies have been completed. For a winning Bidder whose proposal is for a New Unit in the DEF system, the results of the respective facilities study will be incorporated into a Large Generator Interconnection Agreement to be executed between the winning Bidder and DEF.

C. *Regulatory Filings*

Determination of Need and/or Cost Recovery Filings with the Florida Public Service Commission may be required of selected proposals. Proposals that require an application for certification by the Florida Siting Board under the Florida Electrical Power Plant Siting Act will require a Determination of Need by the Florida Public Service Commission. In that event, DEF will be the applicant, and the Bidder will be the co-applicant in proceedings before the Florida Public Service Commission (which will determine the need for the project), the Florida Department of Environmental Protection (which will make a recommendation to the Florida Siting Board concerning site certification), and the Florida Siting Board. Cost Recovery Filings are annual filings associated with the fuel and purchased power clauses and are made after the execution of the applicable written agreement and will be required for all selected proposals. In the case of a proposal that does not require a need determination, pre-approval of such written agreement, as determined by DEF, may be required. The expected regulatory filing date of September, 2014 in the RFP schedule (presented on page 3) is for the Determination of Need Filing, if required, or the written agreement pre-approval filing, if desired. DEF will also require that an application for site certification be filed on or before the PSC need filing date for any project that will require site certification by the Florida Siting Board.

IV. DEF'S "NPGU"

The following data represent preliminary cost and performance estimates for DEF's NPGU and are provided for information purposes only. The final actual cost of the project could be greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. Combined cycle generating unit to be located near DEF's existing Crystal River site in Citrus County, Florida (Citrus CC1).
2. Approximately 1,820 MW (net winter) and 1,640 MW (net summer).
3. Commercial Operation of the facility is proposed to be May 1, 2018.
4. The only fuel source to the unit is natural gas.
5. The estimated total direct cost excluding AFUDC is $ 1,240 million (2013$). This estimate includes the plant interconnection (electrical generator radial connections to the Bulk Electric System) costs identified in Item 11 below but does not include transmission network upgrade costs (or network system impacts associated with the Bulk Electric Systems).
6. The estimated annual levelized capital revenue requirement with AFUDC, excluding transmission system integration related capital costs, is $145.5 million over 35 years.
7. The estimated annual value of deferral of this unit is $63.3/kw-yr (2013$) based on summer fired capacity, which includes plant generation and interconnection construction costs and fixed O&M.
8. The estimated annual fixed O&M is $6.00/kW-yr (2013$). The estimated variable O&M is $2.13/MWh (2013$).
9. The Henry Hub estimated natural gas commodity cost is $3.96/mmBtu (2013$).
10. The following are planning estimates for the first year of operations:

Planned outage rate	8.0 %
Forced outage rate	2.0 %
Minimum load	200 MW
Ramp Rate	50 MW/minute (from minimum to full load)
Summer Fired Capacity	1,640 MW
Summer Unfired Capacity	1,464 MW
Summer Fired Heat Rate	6,850 Btu/kWh (HHV)
Summer Unfired Heat Rate	6,580 Btu/kWh (HHV)
Summer Conditions	90°F, 60% R.H.
Winter Fired Capacity	1,820 MW
Winter Conditions	45°F, 60% R.H.

11. The estimated plant transmission interconnection cost for this unit is $44 million (2013$), excluding AFUDC. The cost associated with the gas lateral will be included in the negotiated fixed transportation contract rate. All costs not provided through this rate are included in the plant capital cost identified in Item 5.

12. A Site Certification as well as an Air Construction/PSD Permit will be required for this unit.

It is DEF's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

General Inflation:	2.5 % per year
Capital structure:	50% debt @ 3.75%
	50% equity @ 10.5%
Discount rate:	6.46%

V. DEF'S SYSTEM SPECIFIC CONDITIONS

During the timeframe of this RFP, the following DEF system conditions are relevant to the responses to this RFP:

- The preferred Bulk Electric System (BES) location for the new DEF (DEF) capacity is in Citrus County. The Citrus County location is preferred because the new capacity is replacing generation that is being retired in the area. In addition this location for new generation is expected to provide transmission reliability benefits for DEF as well as neighboring transmission systems within the Florida Region.

- Other areas in the proximity of Citrus County are expected to have similar reliability benefits but may require additional Transmission Network Upgrades. If the new capacity is not located in the Citrus County vicinity, it is expected that significant Transmission Network Upgrades will need to be constructed within DEF as well as neighboring transmission systems within the Florida Region.

- The connection of the new capacity in Citrus County should be such that it takes advantage of the available transmission capacity that will become available on the BES due to generation retirements in the area.

DEF's long-term 10-year expansion plan was updated in the Summer of 2013 in which the 2018 Citrus County CC was selected as DEF's NPGU. With regards to the Summer 2013 Resource Plan evaluations, the following projected 10 year System Reserve Margins are being provided as follows:

DEF 2013 Ten Year Forecast of Firm Demand, Capacity, and Reserve Margins										
	MW	MW	MW	%			MW	MW	MW	%
	Firm Peak Demand	Installed Capacity	Installed Reserve	Reserve Margin			Firm Peak Demand	Installed Capacity	Installed Reserve	Reserve Margin
	Summer						Winter			
2013	8,944	10,999	2,055	23		**2013**	8,989	12,408	3,419	38
2014	9,005	10,959	1,954	22		**2014**	9,092	12,220	3,128	34
2015	9,164	10,952	1,788	20		**2015**	9,710	12,207	2,497	26
2016	9,169	11,287	2,118	23		**2016**	9,843	12,106	2,262	23
2017	9,230	11,406	2,176	24		**2017**	9,666	12,435	2,769	29
2018	9,400	11,359	1,958	21		**2018**	9,814	12,445	2,631	27
2019	9,823	12,179	2,355	24		**2019**	9,966	13,390	3,424	34
2020	9,994	12,074	2,079	21		**2020**	10,363	13,390	3,027	29
2021	10,063	12,442	2,378	24		**2021**	10,514	13,274	2,760	26
2022	10,229	12,442	2,213	22		**2022**	10,665	13,715	3,050	29

ATTACHMENT A

Key Terms, Conditions and Definitions

KEY TERMS & CONDITIONS

This Attachment A represents some of the Key Terms and Conditions that Duke Energy Florida will require in a Power Purchase Agreement (PPA). The Key Terms & Conditions were developed assuming the Bidder's resources are physically located in the DEF control area. For System Power Proposals, or to the extent the resources are off-system, some definitions, terms, and conditions may not apply or may need to be revised to reflect the location of the resource. This attachment reflects only some of the primary terms and conditions that DEF will require and is not intended to be exhaustive or all-inclusive of the terms and conditions DEF will require in an executed PPA. Bidders should refer to DEF's OATT for specific terms and conditions in the Standard Large Generator Interconnection Agreement that govern the transmission interconnection for New Unit Proposals interconnected to the DEF control area.

SECTION 1. RIGHT OF FIRST REFUSAL
Duke Energy Florida (DEF) shall have the Right of First Refusal to purchase the Facility or to purchase any capacity expansions during the term of the Agreement, upon substantially the same terms and purchase price as that offered to any third party, which option shall be held open for a period of ninety (90) days after Seller's presentation of the terms of such offer to DEF. Notwithstanding the foregoing, any transfer of the Facility or any expansion thereof to any third party shall be permitted only with the prior written approval of DEF, and only upon agreement by a third party to assume all of Seller's obligations under the Agreement. This Right of First Refusal is not applicable to System Power Proposals.

SECTION 2. ADJUSTMENTS TO` FIXED PAYMENTS
Subsequent to the Commercial Operation Date of the Facility and subject to the Seller's meeting all other obligations under the Agreement (including availability requirements), DEF shall accept, purchase, and pay for the Seasonal NDC (as applicable) to be delivered under the Agreement based on the Contract Capacity, subject to the following:

a. If the tested Seasonal NDC is greater than or equal to the Seasonal Contract Capacity, DEF will pay Seller for capacity delivered based on the Seasonal Contract Capacity.

b. If tested Seasonal NDC is lower than the Seasonal Contract Capacity, DEF will pay Seller based on the Seasonal Contract Capacity, after subtracting the daily liquidated damages as specified in Section 3.5, until a re-test of the Facility shows a Seasonal NDC at least equal to the applicable Seasonal Contract Capacity.

c. If Seller fails to achieve an eighty-five percent (85%) EAF on a 12-month rolling average, starting in the second contract year, then the proposed Fixed Payments (Generation Capital, Transmission, Fixed O&M, and Fixed Pipeline Demand/Reservation as specified in Schedule 1 of the Response Package-Attachment C) will be reduced on a sliding-scale basis.

d. No Fixed Payments will be made for those months in which the 12-month rolling average EAF is less than 60%.

e. In any month, if the actual EFOR is greater than the EFOR guarantee, the proposed Fixed Payment will also be reduced by the Availability Adjustment Factor (AAF), where

$$AAF = (1 - EFOR_{actual}) / (1 - EFOR_{guarantee}).$$

The AAF shall not be greater than 1.0.

f. The monthly fixed payment shall thus be
Actual Fixed Payment (AFP) = proposed Fixed Payment * EAF adjustment * AAF.

Fixed Payment Adjustments are not applicable to System sales.

SECTION 3. DEFAULT AND SECURITY

3.1 Operation by DEF Following Event of Default by Seller

a. If during the term of the Agreement DEF becomes entitled to terminate the Agreement due to an Event of Default, then, in lieu of terminating the Agreement, DEF may, in its sole discretion, but without any obligation to do so, assume operational responsibility for the Facility to complete construction, continue operation, complete any necessary repairs, or take such other steps as are appropriate in the circumstances, or may designate a third party or parties to do the same, so as to assure uninterrupted availability of capacity and deliverability of electric energy from the Facility. Seller agrees to fully cooperate with DEF in providing access to the Facility, and permitting DEF to operate the Facility as provided herein. Any payments to Seller shall be made only after any and all costs and expenses (including liquidated damages) of DEF in exercising its rights hereunder are deducted.

b. DEF's exercise of its rights hereunder to operate the Facility and Seller's Interconnection Facilities shall not be deemed an assumption by DEF of any liability of Seller.

c.

Operation by DEF Following Event of Default by Seller is not applicable to System sales.

3.2 Establishment of Security Funds

Seller agrees to establish, fund, and maintain the Security Fund as specified below:

- The Security Fund shall be maintained at Seller's expense, shall be originated by a financial institution or company ("Issuer") acceptable to DEF, and shall be in the form of either of the following, or combination of both:

  (1) An irrevocable standby letter of credit drawn on an Issuer acceptable to DEF; or
  (2) Cash in U.S. Dollars to be held by DEF.

- The amount of security to be required from Seller will be determined based on the following:

Security required for new projects to be developed is shown in the table below.

SECURITY SCHEDULE – NEW PROJECTS		
Timing	Amount	Cumulative Amount
30 days after contract signing	\$40/kW	\$40/kW
12 months after contract signing	\$20/kW	\$60/kW
24 months after contract signing	\$20/kW	\$80/kW
Earlier of 36 months after contract signing or within 30 days after commercial operation	\$20/kW	\$100/kW [a]
10 years after c/o	(\$50/kW)	\$50/kW [a]
15 years after c/o	(\$20/kW)	\$30/kW [a]
During contract term, based on market exposure [b]	Up to \$100/kW	Up to \$200/kW

The following table shows the security required for existing facilities.

SECURITY SCHEDULE – EXISTING FACILITIES		
Timing	Amount	Cumulative Amount
30 days after contract signing	\$40/kW	\$40/kW
Within 10 business days after beginning of term	\$60/kW	\$100/kW [a]
10 years after beginning of term	(\$50/kW)	\$50/kW [a]
15 years after beginning of term	(\$20/kW)	\$30/kW [a]

During contract term, based on market exposure [(b)]	Up to $100/kW	Up to $200/kW

Notes:
(a) Cumulative amount shown excludes the impact of any additional security required based on market exposure – see note (b).
(b) Additional security will be required in the event that DEF's market exposure exceeds the operational security that is otherwise required. DEF's market exposure represents the additional cost that would be required to replace the capacity and energy in the wholesale electric power markets or by constructing a new generation facility.

DEF will assign a Credit Limit to qualified Sellers based on the table below. In order to qualify for a Credit Limit, a Seller must maintain a credit rating from Standard & Poor's (S&P) or Moody's Investors Service (Moody's). A Seller may elect to provide a parent guarantee from a rated entity, in which case the assessment will be based on the guarantor's creditworthiness.

The Credit Limit will be calculated as a percentage of the Seller's Tangible Net Worth (TNW), subject to a maximum amount as shown under Credit Limit Cap. If the S&P and Moody's ratings are not equivalent, then the lower of the two will be used. The total required cash and letter of credit security as determined per above will be reduced by the Credit Limit amount as determined by reference to the table below. If at any time during the term of the agreement, the credit rating changes, then the amount of cash or letter of credit security will be adjusted accordingly.

Credit Rating from S&P / Moody's *	Percentage of TNW	Credit Limit Cap
A-/A3 or better	16%	$50,000,000
BBB+/Baa1	10%	$40,000,000
BBB/Baa2	10%	$30,000,000
BBB-/Baa3	8%	$30,000,000
Below BBB-	0%	$0

The credit support amount resulting from DEF's market exposure will reflect the expected cost to replace the energy and capacity to be provided under the Agreement in the then-current market environment. A replacement price analysis will be performed using statistical methodologies reflective of prevailing market prices and volatilities at the time of the analysis, and other available market information, in the reasonable determination of DEF.

- To the extent a Security Fund is established in the form of a letter of credit, such letter of credit must be an irrevocable, non-transferable standby letter of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an Affiliate of either Party) with such bank having a credit rating of at least A- from S&P and A3 from Moody's and acceptable to the receiving Party in its commercially reasonable discretion, and otherwise being in a form acceptable to DEF. The letter of credit should automatically renew on an annual basis and must be maintained in place for the duration of the Agreement. The letter of credit must specify that it can be drawn upon by DEF if (i) Seller is required to maintain the letter of credit or other form of security under the Agreement, (ii) Seller has failed to replace the letter of credit or provide other acceptable security, and (iii) less than thirty days remain until the expiration date of the letter of credit. If at any time, the issuing bank fails to meet the requirements of this section, Seller is required to replace the letter of credit within 10 business days with an acceptable letter of credit or other allowable form of security, and if Seller fails to do so, DEF may draw on the letter of credit and hold the cash as security until such time as Seller provides a replacement letter of credit. At such time as Seller's obligation to provide security expires, DEF shall, within a reasonable period of time, cooperate with Seller in canceling the letter of credit and/or returning such amounts.

- A Security Fund shall be maintained until such time as (a) the end of the term of the Agreement, or until termination of the Agreement; and (b) all amounts payable from the Security Fund have been paid.

3.3 Liquidated Damages for Seller's Failure to Meet Commercial Operation

a. If Seller fails to achieve Commercial Operation by the Scheduled Commercial Operation Date, Seller shall pay liquidated damages to DEF as specified below:

Event	Liquidated Damages
Failure to attain Commercial Operation by the Scheduled Commercial Operation Date	AFP/30*

* Based on the Seasonal Contract Capacity

Liquidated damages shall be paid for each calendar day of delay until the facility achieves Commercial Operation or until twelve (12) months shall pass, as liquidated damages and not as a penalty. Liquidated damages shall begin accruing the day after failure to meet the scheduled Commercial Operation Date. Liquidated damages shall be payable monthly within ten (10) days of Seller's receipt from DEF of a bill covering the applicable period and shall continue until the Commercial Operation Date is achieved or twelve (12) months have passed. If Seller fails to make such payment within such ten (10) days, DEF may draw on the Security to cover such payment. In the event that Seller fails to achieve Commercial Operation within twelve (12) months of the Scheduled Commercial

Operation Date, DEF shall have the right to terminate the Agreement. If DEF exercises its right to terminate the Agreement, the entire amount of Security plus any accrued interest shall be retained by DEF as liquidated damages. DEF shall also have any and all remedies specified in the Agreement, or as provided by law.

b. If Seller fails to achieve Commercial Operation by the Scheduled Commercial Operation Date, Seller shall be liable for damages to DEF for the costs of replacing the capacity and energy over and above what DEF would have paid Seller for the capacity and energy under the Agreement, and the transactional costs of obtaining the replacement capacity and energy, in addition to any liquidated damages payable under Section 3.3.a.

c. If Seller provides written notice to DEF or it is otherwise determined by DEF at any time after the Effective Date that Seller will not be able to complete the Facility to a state of Commercial Operation, DEF may terminate the Agreement, and Seller shall pay liquidated damages as specified by the following formula, in addition to any liquidated damages payable under Section 3.3a through the date of termination:

$$\left[(\$20/\text{kW} \times \text{Contract Capacity}) + (\$40/\text{kW} \times \text{Contract Capacity}) \times \frac{\text{(No. of days from contract execution to date of notice)}}{\text{(No. of days from contract execution to Scheduled Com. Oper. Date)}} \right]$$

Upon such notice given by DEF, the Agreement shall terminate and Seller waives any rights it may have under the Agreement.

3.4 Damages for Event of Default After Commercial Operation

If a termination of the Agreement occurs as a result of an Event of Default of Seller after attaining Commercial Operation, Seller, for four (4) years subsequent to the date of default, shall be liable for DEF's damages, including, but not limited to, damages to DEF for the costs of replacing the capacity and energy over and above what DEF would have paid Seller for the capacity and energy under the Agreement, and the transactional costs of obtaining the replacement capacity and energy.

3.5 Penalties for Seasonal Contract Capacity Deficiencies

Seller shall pay to DEF an amount to be determined, based on factors that include, without limitation, the difference between the Seasonal Contract Capacity and the tested Seasonal NDC as determined through Facility testing, for each day that the Seasonal NDC remains below the Seasonal Contract Capacity. Assessed penalties shall be paid monthly. Penalties for Seasonal Contract Capacity Deficiencies are not applicable to System sales.

3.6 Penalties for Start Time Deficiencies

If Seller fails to meet the agreed upon Start Time requirements when tested in accordance with agreed upon provisions at any time during the term of the Agreement, then for each failure Seller shall pay DEF an amount to be determined, based on factors that include, without limitation, the applicable Seasonal Contract Capacity for the Facility, until the deficiency is corrected and satisfactorily re-tested. Assessed penalties shall be paid monthly.

3.7 Penalties for Ramp Rate Deficiencies

If Seller fails to meet the agreed upon Ramp Rate requirements when tested in accordance with agreed upon provisions at any time during the term of the Agreement, then for each failure Seller shall pay DEF an amount to be determined, based on factors that include, without limitation, the applicable Seasonal Contract Capacity for the Facility, until the deficiency is corrected and satisfactorily re-tested. Assessed penalties shall be paid monthly.

3.8 Penalties for Reactive Capability Deficiencies

Seller shall pay to DEF an amount to be determined, based on factors that include, without limitation, the difference between the nameplate reactive capability and the tested reactive capability as determined through facility testing, for each day that the capability remains below the posted capability. Assessed penalties shall be paid monthly or the Seller may be billed for the cost incurred by DEF to replace the reactive output of the unit. Penalties for Reactive Capability Deficiencies are not applicable to System Power proposals or units outside the DEF system.

3.9 Payments from Security Funds

In addition to any other remedy available to it, DEF may draw appropriate amounts from the Security Funds to recover the damages owing to it under the Agreement, including but not limited to the recovery of liquidated damages payable under the contract. Seller will be required to refresh Security Funds to maintain such funds at levels established under the contract. No less than two (2) years after the end of the term of the Agreement, the remaining balance of the Security Funds shall be returned to Seller within a reasonable period of time if any funds are remaining in the Security Funds and if no funds are owed to DEF under the Agreement.

SECTION 4. OPERATION OF THE FACILITY

4.1 General

Seller shall operate, maintain, and repair the Facility in a safe, prudent, reliable, and efficient manner in accordance with Good Utility Practice.

4.2 Establishment of Operating Procedures

Seller and DEF shall each appoint an Operating Representative who shall be the primary point of contact between the parties for purposes of this Section within thirty (30) days after the Effective Date. Seller and DEF shall mutually develop written operating procedures no later than ninety (90) days prior to the Scheduled Commercial Operation Date. The operating procedures will be established by mutual agreement based on the design of the Facility and the design of the Interconnection Facilities. The operating procedures will be intended as a guide on how to integrate the Facility into the control area operator's transmission system. Topics covered shall include, but not be limited to, method of day-to-day communications; key personnel list for applicable DEF and Seller operating centers; clearances and switching practices; outage scheduling; daily capacity and energy reports; unit operations log; and reactive power support. In no event shall the operating procedures to be established hereunder be considered as a modification, amendment or waiver of any of the terms and conditions of the Agreement.

4.3 Certification of Maintenance

a. Seller shall obtain at its sole expense an independent engineering review of the entire Facility (including the Interconnection Facilities), its operation and maintenance to assist DEF in monitoring compliance with Good Utility Practice. This review shall also include a review of the environmental compliance of the Facility and its operation and maintenance plan. The independent review will be conducted by an engineering firm other than the firm chosen by Seller to design, construct, operate or maintain the Facility, and furthermore, selection of this engineering firm is subject to DEF's approval. The independent review will be conducted according to the following schedule:

(1) Once every other year for the first ten (10) years following the Commercial Operation Date.

(2) For the remainder of the term of the Agreement, once every calendar year.

b. Seller shall cause the independent engineer to issue a written report to DEF before June 1 of every year in which the independent review has been conducted assessing Facility operation and maintenance and compliance with all applicable environmental licenses, approvals, and permits and stipulating any related remedial or other actions consistent with Good Utility Practice. Such report shall be made available to DEF as soon as it is available to Seller. Seller shall cause these recommendations to be implemented as soon as practical unless Seller and DEF agree otherwise. Seller shall provide written certification of implementation of these recommendations to DEF as soon as they are completed.

c. DEF or its designated agent shall have the right to verify such recommendations by reviewing all pertinent Facility records and by inspecting the Facility, provided that such review and inspection shall not unreasonably interfere with Seller's operations at the Facility.

d. Seller and DEF shall use all reasonable efforts to resolve any disputes between them as to whether any maintenance deficiency exists and/or whether a particular remedy is reasonably necessary to correct a purported deficiency.

e. Seller agrees to undertake promptly and complete any undisputed deficiencies in maintenance and any disputed deficiencies in maintenance as ultimately agreed by Seller and DEF.

4.4 DEF Inspections

Seller shall allow DEF, at any time and with reasonable prior notice, to visit the Facility, including the control room and Interconnection Facilities, to inspect the Facility, review Seller's operating practices, and examine the operating logs. These visits may be made during weekends and nights as well as normal business hours. In exercising such rights, DEF shall not unreasonably interfere with or disrupt the operation of the Facility and DEF shall comply with all of Seller's reasonable safety regulations at the Facility.

SECTION 5. COMPLIANCE WITH LAWS

5.1 General

Seller agrees that it will at all times comply with all federal, state, and local statutes, laws, regulations and public ordinances of any nature relating in any way to the construction, modification, ownership, maintenance and operation of the Facility, and shall procure all necessary governmental permits, licenses, and inspections, and shall pay all fees and charges in connection therewith. Seller shall indemnify and defend DEF from and against any liability, fines, damages, costs, or expenses arising from Seller's failure to comply with the requirements of this Section. Seller further agrees that it will be responsible for all costs of complying with all current laws and any future change(s) in laws.

5.2 Safety and Health

Seller shall comply with all federal, state and local laws and regulations pertaining to health, safety, sanitary facilities and waste disposal. Seller shall meet all requirements of the Occupational Safety and Health Act of 1970 (OSHA), including all amendments. Seller shall also comply with any standards, rules, regulations and orders promulgated under OSHA and particularly with the agreement for state development and enforcement of occupational health and safety standards as authorized by Section 18 of the Act.

5.3 Equal Employment Opportunity

Unless the rules, regulations or orders of the United States Secretary of Labor exempt the Agreement from the provisions of Section 202 of Executive Order No. 11246, dated September 24, 1965, relating to equal employment opportunity, those provisions are, to the extent applicable, made a part of the Agreement.

5.4 NERC and FRCC

Seller shall comply with all standards pertaining to operation, maintenance and planning of the bulk electric system. Compliance penalties assessed to DEF directly due to non-compliance of the Seller shall be passed in full to the Seller for reimbursement.

SECTION 6. ASSIGNMENT

Seller shall not sell or transfer the Facility or any part thereof, and shall not sell, transfer or assign the Agreement or any rights or obligations thereunder, without the prior written consent of DEF, which DEF may withhold in its sole discretion if Seller is unable to demonstrate that the replacement seller and/or operator will not adequately meet the requirements under the contract. A request to sell or transfer the Facility, or to sell, transfer or assign the Agreement must contain the name and location of individuals or firms to whom it is to be assigned, and a detailed description of the proposed transaction. Consent by DEF to sell or transfer the Facility, or to sell, transfer or assign the Agreement shall not relieve the Seller of responsibility for the performance of all obligations under the Agreement. Any sale or transfer of the Facility, and any transfer or assignment of the Agreement shall not jeopardize any of the security given by Seller as provided in Section 3. For purposes of this Section, a transfer or assignment shall include but not be limited to a sale of all or a material interest in the stock of Seller.

SECTION 7. ENVIRONMENTAL REPORTING AND INDEMNITY

7.1 Environmental Compliance

Seller shall construct, maintain and operate the Facility in accordance with all state, federal and local environmental laws, regulations, ordinances, and permits. Seller shall disclose to DEF, as soon as and to the extent known to Seller, any actual or alleged violation of any environmental laws or regulations arising out of or in connection with the construction, operation or maintenance of the Facility, or the alleged presence of environmental contamination at or in connection with the Facility, or the existence of any past or present enforcement, legal or regulatory action or proceeding relating to such alleged violation or alleged presence of environmental contamination. Environmental contamination means the presence of hazardous wastes, hazardous substances, hazardous materials, toxic substances, hazardous air or other hazardous pollutants, and toxic pollutants, as those terms are used in the Resource Conservation and Recovery Act; the Comprehensive Environmental Response, Compensation and Liability Act; the Hazardous Materials Act; the Toxic Substances Control Act; the Clean Air Act; the Safe Drinking Water Act; the Oil Pollution and Hazardous Substances Control Act; and any and all other applicable federal, state, and local laws and regulations as amended, at such levels or quantities or location, or of such form or character, to be in violation of said federal, state, and local laws and regulations.

7.2 Environmental Indemnity

Seller shall indemnify, defend and hold DEF harmless against any and all claims, demands, losses, liabilities, expenses, fines and penalties, including interest and attorney fees, resulting from any alleged violation of applicable federal, state or local environmental laws or regulations arising out of Seller's construction, operation, maintenance or ownership of the Facility or the Facility site, or the presence of any environmental contamination at or in connection with the Facility.

SECTION 8. REGULATORY OUT

Notwithstanding anything to the contrary in the Agreement, if DEF, at any time during the term of the Agreement, fails to obtain or is denied the authorization of the Florida Public Service Commission ("FPSC"), or the authorization of any other legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over DEF's rates and charges, to recover from its customers all of the payments required to be made to the Seller under the terms of the Agreement or any subsequent amendment hereto, DEF may, at its sole option, adjust the payments made under the Agreement to the amount(s) which DEF is authorized to recover from its customers. In the event that DEF so adjusts the payments to which the Seller is entitled under the Agreement, then, without limiting or otherwise affecting any other remedies which the Seller may have hereunder or by law, the Seller may, at its sole option, terminate the Agreement upon (180) days written notice to DEF. If such determination of disallowance is ultimately reversed and such payments previously disallowed are found to be recoverable, DEF shall pay all withheld payments, with interest as set for refunds under the Federal Power Act pursuant to 18 C.F.R. §35.19a. Seller acknowledges that any amounts initially received by DEF from its ratepayers, but for which recovery is subsequently disallowed and charged back to DEF, may be offset or credited, with interest as set for refunds under the Federal Power Act pursuant to 18 C.F.R. §35.19a, against subsequent payments to be made by DEF to the Seller under the Agreement.

If, at any time, DEF receives notice that the FPSC or any other legislative, administrative, judicial or regulatory body seeks or will seek to prevent full recovery by DEF from its customers of all payments required to be made under the terms of the Agreement or any subsequent amendments to the Agreement, then DEF shall, within five business days of such action, give written notice thereof to the Seller. DEF shall use its best efforts to defend and uphold the validity of the Agreement and its right to recover from its customers all payments required to be made by DEF hereunder, and will cooperate in any effort by the Seller to intervene in any proceeding challenging, or to otherwise be allowed to defend, the validity of the Agreement and the right of DEF to recover from its customers all payments to be made by it hereunder.

The Parties do not intend this Section 8 to grant any rights or remedies to any third party(ies) or to any legislative, administrative, judicial or regulatory body; and this Section 8 shall not operate to release any person from any claim or cause of action which the Seller may have relating to, or to preclude the Seller from asserting, the validity or enforceability of any other obligation undertaken by DEF under the Agreement.

DEFINITIONS – FOR PURPOSES OF THIS RFP ONLY

"Agreement" means the Power Purchase Agreement entered into between Duke Energy Florida (DEF) and the "Seller."

"Commencement Date" means the date power is first accepted under this Agreement, but no later than May 1, 2018.

"Commercial Operation" means operation of the Facility commencing on the Commercial Operation Date and continuing until termination or expiration of the Agreement.

"Commercial Operation Date" means the later of (a) first day of the month following the date that the Facility has been satisfactorily completed and tested by Seller, or (b) the Commencement Date.

"Delivery Point" means the point at which deliveries of capacity and energy under the Agreement are required to be made and shall be measured which, for any Facility located within DEF's control area, shall be the Point of Interconnection; and, for any Facility located outside DEF's control area, shall be the physical point at which connection is made between DEF's system and the system of the Wheeling utility adjacent to DEF's control area which will deliver the capacity and energy to such point from the Facility or from other Wheeling utilities, as the case may be.

"Effective Date" means the date set forth in the preamble to the Agreement; generally, the contract execution date.

"Equivalent Availability Factor" or "EAF" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Equivalent Forced Outage Rate" or "EFOR" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Facility" or "Project" means the equipment, spare parts inventory, lands, property, buildings, generators, step-up transformers, boilers, output breakers, transmission lines and facilities used to connect to the Delivery Point or to the Facility's point of interconnection with the Wheeling utility, protective and associated equipment, improvements, and other tangible and intangible assets, property rights and contract rights reasonably necessary for the construction, operation and maintenance of the Facility.

"FRCC" means the Florida Reliability Coordinating Council.

"Good Utility Practice" means the practices, methods and acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy and expedition. With respect to the Facility, Good Utility Practice(s) include, but are not limited to, taking reasonable steps to ensure that:

1. adequate equipment, materials, resources and supplies, including Primary Fuel and Secondary Fuel (with minimum inventory levels) are available to meet the needs of the Facility;

2. sufficient management and operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently and in coordination with the transmission system control area operator and are capable of responding to reasonably foreseeable emergency conditions whether caused by events on or off the site of the Facility;

3. preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long term and safe operation, and are performed by knowledgeable, trained and experienced personnel utilizing proper equipment and tools;

4. appropriate monitoring and testing is done to ensure equipment is functioning as designed;

5. equipment is not operated in a negligent or reckless manner, or in a manner unsafe to workers, the general public or the transmission system control area operator or contrary to environmental laws or regulations or without regard to defined limitations such as steam pressure, temperature and moisture content, chemical content of make-up water, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, rotational speed, polarity, synchronization and/or control system limits; and

6. the equipment will function properly under both normal and emergency conditions at the Facility and/or the transmission system.

<u>"Interconnection Facilities"</u> means all land, easements, materials, equipment and facilities installed for the purpose of interconnecting the Facility to the Delivery Point to facilitate the transfer of electric energy in either direction, including but not limited to connection, transformation, switching, metering, relaying, communications equipment, safety equipment, and any necessary additions and reinforcements to the control area operator's transmission system required for safety or system security as a result of the interconnection between the Facility and the control area operator's transmission system.

<u>"Milestone Date"</u> means the date by which the Seller is required to complete a specified task in accordance with the Milestone Schedule.

"Milestone Schedule" means the Milestone Schedule set forth in the Agreement, as such Milestone Schedule may be revised in accordance with the terms and conditions of the Agreement.

"MW" means megawatt or megawatts.

"NERC" means the North American Electric Reliability Council.

"Net Dependable Capacity" or "NDC" means the maximum net sustainable output of the Facility in MW that can be delivered to the Delivery Point (after deducting plant auxiliary loads and other losses), based on a performance test.

"Net Electrical Output" means all of the Facility's electric generating output after deducting plant auxiliary loads and any transmission losses between the Facility and the Delivery Point, as measured by metering devices owned by DEF.

"Point of Interconnection" shall mean the point where the Seller's Interconnection Facilities connect to the Company's transmission system.

"Project Lender" means the lender or lenders providing the initial construction and/or permanent debt financing for the Facility, and any fiscal agents, trustees, or other nominees acting on their behalf.

"Ramp Rate" means the minimum rate change in Net Electrical Output per minute over the period beginning at the time when the Seller is instructed to change the Facility's Net Electrical Output, and ending at the time that such Net Electrical Output is achieved, based on performance testing.

"Reactive Capability" means the lesser of the maximum reactive power (MVar) output at full load real power (MW) output based on manufacturer ratings or the reactive power output associated with meeting the voltage schedule contained in the generator interconnect agreement with the transmission provider.

"Scheduled Commercial Operation Date" means the Milestone Date by which Seller is required to achieve Commercial Operation.

"Seasonal Contract Capacity" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Seasonal NDC" means the Summer NDC and/or the Winter NDC, as applicable.

"Security Funds" means the security fund as defined in Section 3.2.

"Seller" means the party that is obligated to sell and deliver power to Duke Energy Florida as specified in this Agreement.

"Start Time" means the maximum time required to synchronize the Facility to the control area operator's transmission system and achieve minimum load beginning when DEF instructs the Seller to start the Facility from a cold shut-down condition.

"Summer Contract Capacity" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Summer NDC" means the NDC for the Summer Period, corrected for ambient conditions.

"Summer Period" shall be the months specified in Section II.E of the Response Package.

"System" means Power System as defined in the RFP Solicitation Document.

"Wheeling" means the transmission of electric power from the electrical system of one utility to the electrical system of another utility, either directly or through the system of one or more other utilities.

"Winter Contract Capacity" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Winter NDC" means the NDC for the Winter Period, corrected for ambient conditions.

"Winter Period" shall be the months specified in Section II.E of the Response Package.

Progress Energy Florida, Inc.
Ten-Year Site Plan

April 2013

2013-2022

Submitted to:
Florida Public Service Commission

Progress Energy

TABLE OF CONTENTS

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LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

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. Florida Power Corporation doing business as (d/b/a) Progress Energy Florida, Inc.'s (PEF) TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

PEF'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 PEF'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 PEF'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

Progress Energy

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUHCA) effective February 8, 2006. Subsequent to that date, Duke Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company.

AREA OF SERVICE

PEF has an obligation to serve approximately 1.6 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. PEF is interconnected with 22 municipal and nine rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the Florida Public Service Commission (FPSC). PEF'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 PEF 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

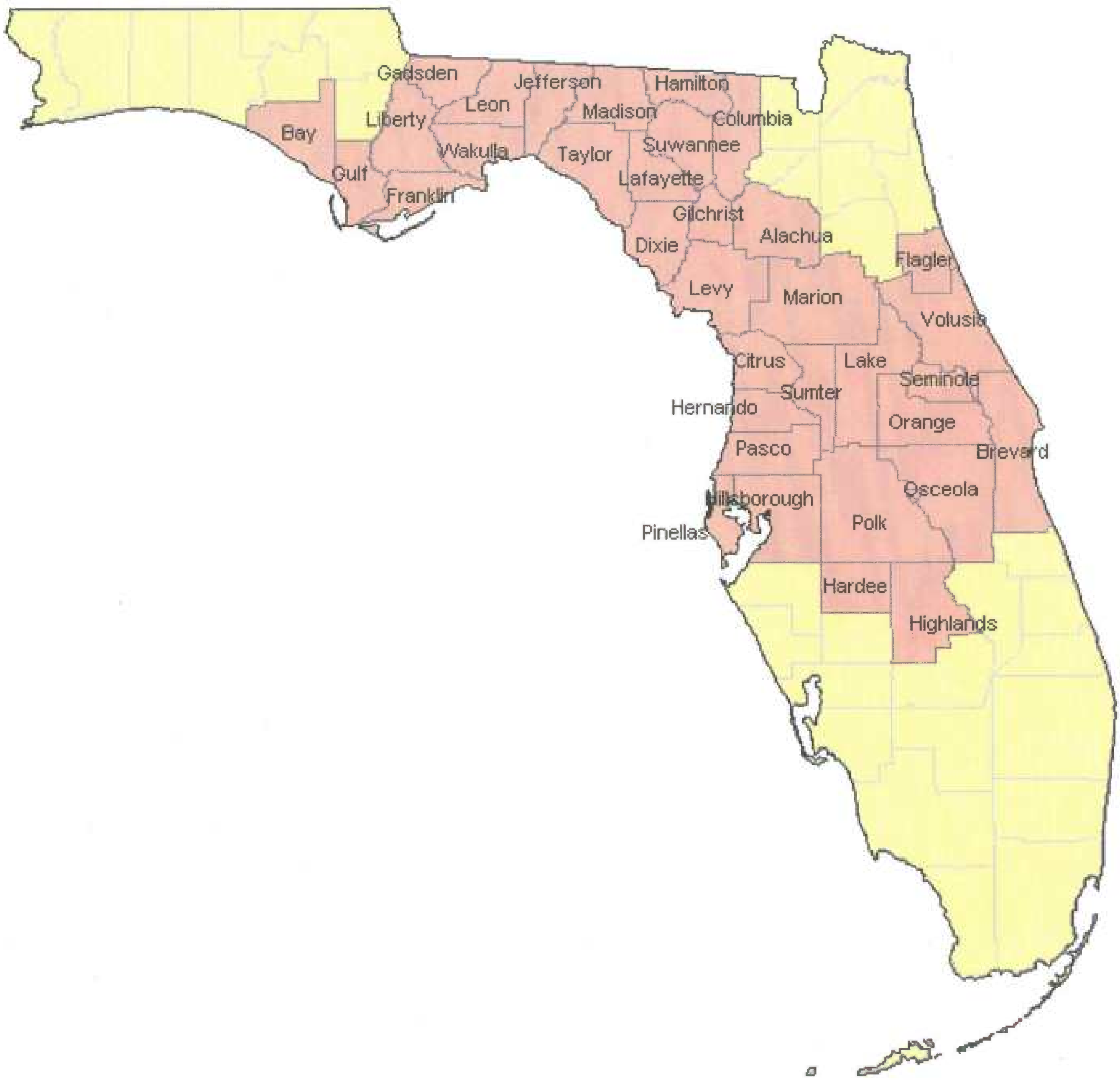
The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 405,000 customers participated in the residential Energy Management program at the end of

2012, contributing about 639 MW of winter peak-shaving capacity for use during high load periods. PEF'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, 2012, PEF had total summer capacity resources of 12,092 MW consisting of installed capacity of 9,884 MW (excluding Crystal River Unit 3 joint ownership) and 2,208 MW of firm purchased power. Additional information on PEF's existing generating resources can be found in Schedule 1 and Table 3.1.

FIGURE 1.1
PROGRESS ENERGY FLORIDA
County Service Area Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL	***	10/74		556,200	501	517
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL	***	10/78		556,200	510	530
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	3 *	CITRUS	NP	NUC		TK			3/77	1/2013	890,460	789	805
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	RFO	PL	TK/RR	***	11/53	*****	34,500	28	28
SUWANNEE RIVER	2	SUWANNEE	ST	NG	RFO	PL	TK/RR	***	11/54	*****	37,500	30	30
SUWANNEE RIVER	3	SUWANNEE	ST	NG	RFO	PL	TK/RR	***	10/56	*****	75,000	71	73
												4,220	**4,300**
COMBINED-CYCLE													
BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	***	6/09		1,253,000	1,074	1,235
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
												3,191	**3,665**
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	85	108
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	43	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	309	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	61	78
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			1/94		43,000	46	47
												2,473	**3,031**
											TOTAL RESOURCES (MW)	**9,884**	**10,996**

* REPRESENTS PEF OWNERSHIP OF UNIT WHICH IS APPROXIMATELY 91.8%. IN FEBRUARY 2013, PEF ANNOUNCED PLANS TO RETIRE CR3 AND NOT RETURN THE UNIT TO SERVICE FROM AN EXTENDED OUTAGE.

** 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. RFO TO BE PHASED OUT WITH UNIT RETIREMENTS OR UNIT GAS CONVERSIONS.

**** CRYSTAL RIVER UNITS 1 & 2 ESTIMATED TO BE SHUTDOWN BY 4/2016; PEF CONTINUES TO EVALUATE OPTION FOR CONTINUED OPERATIONS. SEE CHAPTER 3.

***** SUWANNEE STEAM UNITS ESTIMATED TO BE SHUTDOWN BY 6/2018.

****** PEAKERS at AVON PARK, HIGGINS, RIO PINAR, TURNER P1 & P2 ARE ESTIMATED TO BE PUT IN COLD STAND-BY OR RETIRED BY 6/2016.

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

CHAPTER 2
FORECAST OF ELECTRIC POWER DEMAND
AND
ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents PEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). PEF's customer growth is expected to average 1.5 percent between 2013 and 2022, which is more than the ten-year historical average of 1.0 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 PEF 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 -0.7 percent per year between 2003 and 2012 due primarily to the economic recession and the weak economic recovery that followed. Milder than normal weather conditions during 2012 also contributed to the weak results. The 2013 to 2022 period is expected to improve by an average growth rate of 1.5 percent per year due to expected higher 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 nearly double over this time period.

Summer net firm demand grew an average 0.8 percent per year during the last ten years. The projected ten year period summer net firm demand growth rate of 1.5 percent is primarily driven by a stronger economy improving net firm retail demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided on the following pages:

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 Summer Peak Demand (MW)
3.2	History and Forecast of Winter Peak Demand (MW)
3.3	History and Forecast of Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS 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	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2003	3,264,521	2.451	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,339,365	2.447	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,428,268	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,504,907	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,532,104	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,743	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,397	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,408	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,873	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,636,514	2.493	18,251	1,458,690	12,512	11,723	163,297	71,792
FORECAST:								
2013	3,683,572	2.490	18,959	1,479,346	12,816	11,569	165,511	69,899
2014	3,719,750	2.480	19,405	1,499,899	12,938	11,776	168,050	70,074
2015	3,770,309	2.475	19,877	1,523,357	13,048	11,956	171,170	69,849
2016	3,818,679	2.470	20,287	1,546,024	13,122	12,068	174,439	69,182
2017	3,868,716	2.465	20,700	1,569,459	13,189	12,145	177,706	68,343
2018	3,919,678	2.460	21,107	1,593,365	13,247	12,202	181,060	67,392
2019	3,970,810	2.455	21,514	1,617,438	13,301	12,263	184,458	66,481
2020	4,029,595	2.455	21,904	1,641,383	13,345	12,328	187,857	65,624
2021	4,087,465	2.455	22,303	1,664,955	13,396	12,393	191,218	64,811
2022	4,144,418	2.455	22,712	1,688,154	13,454	12,458	194,526	64,043

PROGRESS 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
HISTORY:							
2003	4,001	2,643	1,513,810	0	29	2,946	37,958
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
FORECAST:							
2013	3,294	2,343	1,405,890	0	25	3,137	36,984
2014	3,270	2,340	1,397,436	0	25	3,207	37,683
2015	3,300	2,340	1,410,256	0	25	3,312	38,470
2016	3,308	2,340	1,413,675	0	25	3,381	39,069
2017	3,341	2,340	1,427,778	0	24	3,433	39,643
2018	3,413	2,340	1,458,547	0	24	3,484	40,230
2019	3,490	2,340	1,491,453	0	24	3,532	40,823
2020	3,568	2,340	1,524,786	0	24	3,580	41,404
2021	3,596	2,340	1,536,752	0	24	3,612	41,928
2022	3,575	2,340	1,527,778	0	24	3,641	42,410

PROGRESS 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
HISTORY:					
2003	3,359	2,594	43,911	21,665	1,510,516
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	826	4,007	41,214	25,480	1,649,839
FORECAST:					
2013	1,410	2,392	40,786	25,818	1,673,018
2014	1,474	2,408	41,565	26,193	1,696,482
2015	1,627	2,452	42,549	26,664	1,723,531
2016	1,822	2,530	43,421	27,205	1,750,008
2017	1,705	2,476	43,824	27,744	1,777,249
2018	1,675	2,547	44,452	28,351	1,805,116
2019	1,630	2,584	45,037	28,966	1,833,202
2020	1,637	2,613	45,654	29,582	1,861,162
2021	1,609	2,642	46,179	30,191	1,888,704
2022	1,610	2,669	46,689	30,792	1,915,812

PROGRESS 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
HISTORY:										
2003	8,881	887	7,994	300	355	169	44	161	75	7,776
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	1618	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	402	9,381	267	326	355	100	278	124	8,333
FORECAST:										
2013	10,462	937	9,525	271	330	382	103	287	124	8,964
2014	10,572	871	9,702	274	335	408	107	298	124	9,026
2015	10,773	873	9,901	277	340	432	110	306	124	9,185
2016	11,066	977	10,089	276	345	452	113	314	124	9,441
2017	11,189	894	10,295	286	368	470	116	320	124	9,504
2018	11,391	894	10,497	288	373	486	120	326	124	9,674
2019	11,607	894	10,713	303	378	501	123	332	124	9,846
2020	11,823	894	10,929	318	383	518	126	337	124	10,017
2021	11,928	794	11,134	326	388	533	129	341	124	10,086
2022	12,121	794	11,327	326	393	548	133	345	124	10,252

Historical Values (2003 - 2012):
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 (2013 - 2022):
Cols. (2) - (4) = forecasted peak witiout load control, 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).

PROGRESS 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
HISTORY:										
2002/03	11,553	1,538	10,015	271	795	312	27	122	191	9,833
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	210	7,702
FORECAST:										
2012/13	11,203	909	10,294	254	672	735	100	216	239	8,987
2013/14	11,386	942	10,445	256	681	786	103	230	240	9,090
2014/15	12,081	1,445	10,636	259	690	836	106	239	242	9,709
2015/16	12,274	1,447	10,828	258	699	877	109	246	243	9,841
2016/17	12,423	1,394	11,029	267	717	917	113	254	245	9,910
2017/18	12,624	1,394	11,230	269	750	947	116	260	247	10,036
2018/19	12,840	1,394	11,446	283	759	975	119	267	250	10,188
2019/20	13,055	1,394	11,661	297	768	1,009	122	273	252	10,335
2020/21	13,263	1,394	11,869	305	777	1,040	126	276	254	10,485
2021/22	13,459	1,394	12,065	305	786	1,069	129	279	256	10,635

Historical Values (2003 - 2012):
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 (2013 - 2022):
Cols. (2) - (4) forecasted peak without load control and conservation.
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).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
HISTORY:									
2003	45,234	402	357	564	37,957	3,359	2,595	43,911	47.7
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	826	4,007	41,214	51.7
FORECAST:									
2013	43,146	778	718	864	36,984	1,410	2,392	40,786	51.8
2014	43,995	821	745	864	37,683	1,474	2,408	41,565	52.2
2015	45,039	857	769	864	38,470	1,627	2,452	42,549	50.0
2016	45,970	891	792	866	39,069	1,822	2,530	43,421	50.2
2017	46,418	918	812	864	39,643	1,705	2,476	43,824	50.5
2018	47,091	944	831	864	40,230	1,675	2,547	44,452	50.6
2019	47,720	969	850	864	40,823	1,630	2,584	45,037	50.5
2020	48,384	996	868	866	41,404	1,637	2,613	45,654	50.3
2021	48,950	1,021	886	864	41,928	1,609	2,642	46,179	50.3
2022	49,500	1,044	903	864	42,410	1,610	2,669	46,689	50.1

* 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 historical load factors which are based on the actual summer peak demand which became the annual peak for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

PROGRESS 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 2012		FORECAST 2013		FORECAST 2014	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	8,722	3,097	10,128	3,060	10,246	3,152
FEBRUARY	8,519	2,799	8,741	2,722	8,836	2,774
MARCH	6,135	3,128	7,708	2,959	7,804	2,990
APRIL	7,004	3,164	8,022	3,050	8,075	3,080
MAY	7,942	3,780	8,973	3,661	9,036	3,706
JUNE	8,185	3,699	9,389	4,006	9,456	4,093
JULY	9,026	4,278	9,564	4,123	9,636	4,212
AUGUST	8,850	4,218	9,669	4,213	9,742	4,296
SEPTEMBER	8,103	3,797	8,969	3,866	9,026	3,958
OCTOBER	7,790	3,478	8,473	3,265	8,544	3,342
NOVEMBER	5,749	2,739	7,081	2,812	7,104	2,855
DECEMBER	6,555	3,036	8,038	3,051	8,658	3,107
TOTAL		41,213		40,788		41,565

NOTE: Recorded Net Peak demands and System requirements including off-system wholesale contracts.

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. PEF'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. PEF'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.

PROGRESS 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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,663	4,543	5,381	5,369	5,484	4,925	4,951	4,726	4,497	4,030	3,843	3,814
(3)	RESIDUAL	TOTAL	1,000 BBL	380	89	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	380	89	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	256	160	316	325	402	846	835	517	458	236	168	241
(9)		STEAM	1,000 BBL	61	60	63	39	39	18	12	11	14	10	10	10
(10)		CC	1,000 BBL	8	1	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	187	99	253	286	363	827	823	506	444	226	157	231
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	183,363	187,251	177,253	188,213	192,618	185,192	174,966	194,327	206,682	230,055	241,711	245,067
(14)		STEAM	1,000 MCF	23,033	26,837	25,055	32,353	35,813	31,908	29,034	26,936	28,087	25,910	26,650	25,709
(15)		CC	1,000 MCF	151,176	155,717	142,259	145,347	144,571	138,185	131,519	155,331	167,608	195,979	207,251	209,755
(16)		CT	1,000 MCF	9,154	4,697	9,939	10,512	12,234	15,100	14,413	12,060	10,986	8,167	7,810	9,603
	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	8,494	9,464	10,165	31,831	45,266	32,360	25,945	14,297	9,113	9,411
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	0	0	6,773	6,681	8,633	12,078	11,481	9,360	10,294	6,000	5,592	6,018
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	0	0	229	223	244	80	0	0	0	0	0	0

PROGRESS 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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,917	1,558	663	654	845	4,490	6,449	4,231	3,175	1,252	409	458
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,809	10,003	11,761	11,758	12,003	10,882	10,952	10,456	9,926	8,777	8,336	8,288
(4)	RESIDUAL	TOTAL	GWh	187	46	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	187	46	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	81	104	84	95	123	281	273	167	146	81	57	88
(10)		STEAM	GWh	2	63	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	4	1	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	75	39	84	95	123	281	273	167	146	81	57	88
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,571	23,997	23,159	24,423	24,855	23,478	22,124	25,481	27,531	31,592	33,532	33,946
(15)		STEAM	GWh	1,826	2,175	2,075	2,849	3,198	2,744	2,433	2,307	2,465	2,244	2,327	2,251
(16)		CC	GWh	20,775	21,469	20,204	20,644	20,580	19,504	18,539	22,168	24,140	28,612	30,498	30,818
(17)		CT	GWh	970	353	879	931	1,077	1,230	1,152	1,006	926	736	707	878
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,423	2,767	2,174	1,571	1,565	1,657	1,656	1,652	1,640	1,577	1,522	1,523
	RENEWABLES		GWh	1,243	1,183	1,286	1,290	1,243	1,267	1,265	1,262	1,252	1,182	1,107	1,131
	IMPORT FROM OUT OF STATE		GWh	2,275	1,559	1,659	1,775	1.917	1,365	1,104	1,202	1.368	1,193	1,216	1,255
	EXPORT TO OUT OF STATE		GWh	-16	-4	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	42,490	41,213	40,786	41,565	42,549	43,421	43,824	44,452	45,037	45,654	46,179	46,689

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

PROGRESS 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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE 1/		%	4.5%	3.8%	1.6%	1.6%	2.0%	10.3%	14.7%	9.5%	7.1%	2.7%	0.9%	1.0%
(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		%	25.4%	24.3%	28.8%	28.3%	28.2%	25.1%	25.0%	23.5%	22.0%	19.2%	18.1%	17.8%
(4)	RESIDUAL	TOTAL	%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.4%	0.1%	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	%	0.2%	0.3%	0.2%	0.2%	0.3%	0.6%	0.6%	0.4%	0.3%	0.2%	0.1%	0.2%
(10)		STEAM	%	0.0%	0.2%	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	%	0.2%	0.1%	0.2%	0.2%	0.3%	0.6%	0.6%	0.4%	0.3%	0.2%	0.1%	0.2%
(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	%	55.5%	58.2%	56.8%	58.8%	58.4%	54.1%	50.5%	57.3%	61.1%	69.2%	72.6%	72.7%
(15)		STEAM	%	4.3%	5.3%	5.1%	6.9%	7.5%	6.3%	5.6%	5.2%	5.5%	4.9%	5.0%	4.8%
(16)		CC	%	48.9%	52.1%	49.5%	49.7%	48.4%	44.9%	42.3%	49.9%	53.6%	62.7%	66.0%	66.0%
(17)		CT	%	2.3%	0.9%	2.2%	2.2%	2.5%	2.8%	2.6%	2.3%	2.1%	1.6%	1.5%	1.9%
(18)	OTHER 2/														
	QF PURCHASES		%	5.7%	6.7%	5.3%	3.8%	3.7%	3.8%	3.8%	3.7%	3.6%	3.5%	3.3%	3.3%
	RENEWABLES		%	2.9%	2.9%	3.2%	3.1%	2.9%	2.9%	2.9%	2.8%	2.8%	2.6%	2.4%	2.4%
	IMPORT FROM OUT OF STATE		%	5.4%	3.8%	4.1%	4.3%	4.5%	3.1%	2.5%	2.7%	3.0%	2.6%	2.6%	2.7%
	EXPORT TO OUT OF STATE		%	0.0%	0.0%	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. PEF's forecasting framework utilizes a set of econometric models 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 DSM programs.

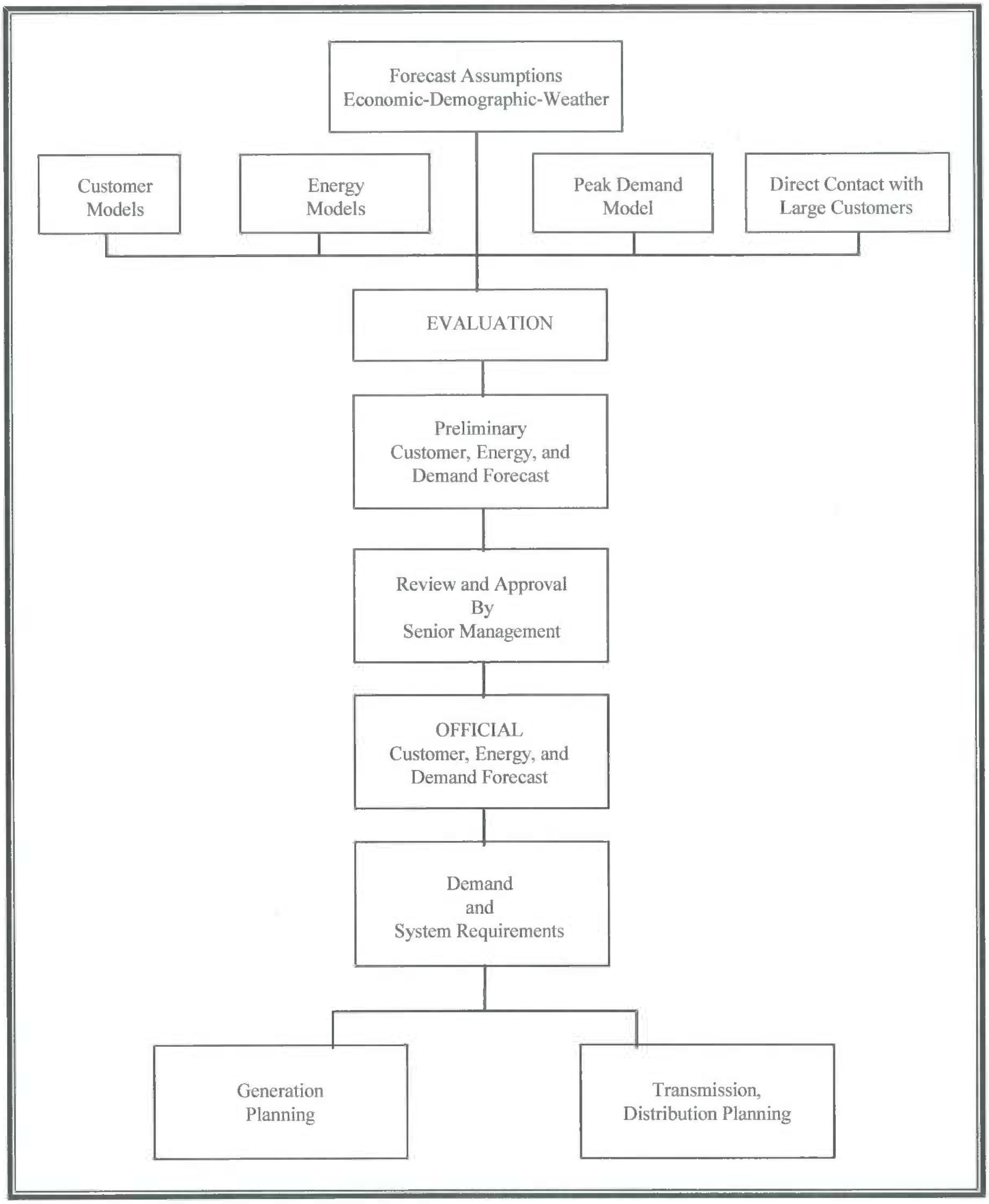
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for 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 "modified" 20-year average of conditions at seven weather stations across Florida (Saint Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona Beach, and Tallahassee). For kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 20-year average of the service area weighted billing month degree-days then removes the two largest outliers from this average for each of the 12 months for both the heating season and cooling season. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the Tampa, Orlando, and Tallahassee weather stations; the other weather stations are not used in developing the historic average because they lack the historic hourly data needed for peak-weather normalization.

2. The population projections produced by the BEBR at the University of Florida as published in "Florida Population Studies," Bulletin No. 162 (March 2012) provided the basis for development of the customer forecast. The projection incorporated the results of the 2010 decennial census for Florida counties which includes a historical review of the years 1991-2009 for each county. The PEF methodology aggregates a 29 county area representative of the retail service territory. National and Florida economic projections produced by Moody's Analytics in their August 2012 forecast provided the basis for development of the energy forecast.

3. Within the PEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for over 30 percent of the industrial class MWh sales in 2012. 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 price of the raw mined commodity often dictates production levels. Load and energy consumption at the PEF-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, a weaker U.S. currency

value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities have become more competitive overseas which has contributed to higher crop production at home. Second, a weak U.S. dollar results in U.S. fertilizer producers to become more price competitive relative to foreign producers. The PEF forecast calls for an increase in annual electric energy consumption levels for fertilizer producers. 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 PEF's rates versus competitors' rates play a role as to where a mining customer directs output from self-owned generation facilities. This can reduce load for the utility.

4. PEF supplies load and energy service to wholesale customers on a "full," "partial," and "supplemental" 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) customer 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, Gainesville, Homestead and Winter Park.

   PEF has negotiated several power sales agreements with SECI beginning in various years over the ten-year horizon. An existing contractual arrangement is a "supplemental" service contract providing energy over and above stated levels they commit to supply themselves. This contract terminates in December 2013. Stratified partial requirements agreements over the next ten years include base strata, intermediate strata, a seasonal peaking strata and a system average sale. Finally, an agreement to provide interruptible service at a SECI metering site has also been included in this projection.

5. This forecast assumes that PEF 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 assumes an increase of over 15 MW of self-service generation beginning in 2013 from two customers. PEF will supply the supplemental load of self-service cogeneration customers. While PEF 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 PEF 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.

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2012 as the nation displayed positive signs of growth. Most economic indicators pointed to better days ahead but Washington policy-makers continued to debateover pro-growth versus deficit reduction strategies which prolong uncertainty for consumers, employers and capital investment decision-makers. Consumer confidence and sentiment surveys have bounced back as the unemployment rate has dropped and stock market indexes are at double the levels reached at the trough of the recession.

This forecast tried to weigh two opposing opinions of future economic outlooks. One view sees continued improvement in several economic series. This view suggests that eventually, 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. Manufacturing activities returning to the U.S. have been reported. An alternative view anticipates an increasingly weaker national picture driven by weak demand from the debt-laden Euro-Zone economies. Policies requiring severe austerity measures to reduce sovereign debt levels are expected to lead to weak growth in Europe as well as in the U.S. This view suggests that a continued de-leveraging of the American consumer, lower job growth and tight credit standards dim hopes for a healthy short-term recovery. The commencement of the Affordable Care Act in 2014 continues to drive uncertainty for employers as a lack of understanding still remains.

The Federal Reserve Board policy of "quantitative easing" can claim some success for the improved housing market. Low mortgage rates have led to very low inventories of homes for sale and prices have begun to rise. Higher home prices help both homeowners and lenders by improving their financial security. Probably the best test that the economy has turned the corner will come as job growth reaches over 200,000 jobs per month and gains in "earned" income out-grow inflation.

In summary, the short term assumptions underlying this forecast are based on an economic outlook that involves a slower than normal recovery. Financial instability, whether it is called the "Fiscal Cliff", "sequestration" or "deficit reduction", will likely reduce economic growth from the public sector as well as stifle private sector decision-making in the near term.

LONG-TERM ECONOMIC ASSUMPTIONS

The long term economic outlook assumes that changes in economic and demographic conditions, as well as technological change impacting the electric utility industry, will follow a historical behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations or rapid penetration of a significant technological breakthrough impacting electric utility energy sales during this period.

Population Growth Trends

This forecast assumes Florida will experience higher near-term population growth as economic recovery takes hold, as reflected in the BEBR projections. Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. Florida is expected to continue to be an attractive state for the increasing population of baby-boom generation retirees. Working against this significant trend will be several aesthetic and economic factors. First, the enormous growth in population and corresponding development of the 1980s, 1990s, and early 2000s made portions of Florida less desirable and less affordable for retirement living. This perceived diminished quality of retiree life, along with increasing competition from neighboring states, will cause a slight decline in Florida's share of these prospective new residents over the long term. Second, and to a lesser extent, there is a lingering fear for safety and expense from hurricane damage.

Economic Growth Trends

The Florida economy has always relied upon agriculture, tourism and development to serve as its economic growth engine. Recent efforts have been made to further diversify into the bioscience-related industries with some success. Setbacks, such as the severe financial crisis and the ending of a large piece of NASA's space flight industry, however, have left Florida significantly challenged. Declining revenues have forced budget cutbacks in most government departments and delays or cancelation of many state-supported projects. As with every previous recession, however, conditions are anticipated to improve and economic growth is assumed to return.

As a state with growing energy needs and a rapidly increasing average-aged population, Florida stands to benefit from strides currently being made in the health, technology and energy sectors. The nation has also realized the economic benefits that come from trade. Several Florida ports are being expanded to handle larger shipping vessels that will travel through an expanded Panama Canal. Florida has developed close trading ties with South America which has several countries that have developed into major emerging markets. Renewing economic ties with Cuba is now a reasonable possibility that could benefit the state. These trends along with an eventual turnaround in the state housing sector will lead to the assumed level of economic growth in the forecast.

FORECAST METHODOLOGY

The PEF forecast of customers, energy sales, and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. 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 annual data for 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. Normal weather, which is assumed throughout the forecast horizon, is based on a twenty-year modified average of heating and cooling degree-days by month as measured at several weather stations throughout Florida for energy projections and temperatures around the hour of peak for the firm retail demand forecast. Projections of PEF's demand-side management (conservation) programs are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of 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 equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements, 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 annual customer growth with PEF service area population growth. County level population projections for counties in which PEF 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. The measure of cooling degree-days utilized here differs slightly from that used in the residential sector reflecting different temperature base sensitivities, when heating and cooling load become observable. Commercial customers are projected as a function of the number of residential customers served.

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 and a Florida industrial production index, the real price of electricity to the industrial class, 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 four customers, the forecast is dependent upon information received from direct customer contact. PEF 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 recently. 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 with the size of the service area. The level of government services, and thus energy, can be tied to the population base, as well as to the state of the economy. 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 heating and cooling degree-days (class specific), the real price of electricity 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).

Seminole Electric Cooperative, Inc. (SECI) is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average historical load shape of total SECI load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has several agreements with SECI to serve various types of stratified demand levels deemed by their resource planners as necessary to meet their load characteristics and reserve requirements.

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 PEF. The full requirement customers' energy projections grow at a rate that approximates their historical trend with additional information coming from the respective city officials. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, Gainesville and Winter Park, and another power provider Reedy Creek Improvement District (RCID). In each case, these customers contract with PEF for a specific level and type of demand 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.

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, PEF's coincident system peak is separated into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical cumulative effects of company-aided conservation activity or the activation of PEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand assuming no utility induced conservation or 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 total system customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data 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 PEF'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 PEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. The SECI supplemental demand projection is based on SECI's projection of total load in the PEF control area. The level of MW to be served by PEF is dependent upon the amount of generation resources SECI supplies itself or contracts from others. 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.

PEF "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 PEF'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 PEF. In this Order, the FPSC modified PEF's DSM Plan to consist of those existing programs in effect as of the date of the Order.

The following tables show the 2010, 2011 and 2012 achievements from PEF'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

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

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

PEF'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. 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. The following is a brief description of these programs. In 2012, PEF 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 PEF provides incentives. The revisions to the programs are incorporated in the descriptions below.

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides customers with an analysis of their current energy use and 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 PEF 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); 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

This is the umbrella program 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 PEF 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 PEF'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 at Progress Energy's website. 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 PEF 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 PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF'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 systems(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 PEF'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 PEF 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 PEF's request.

Interruptible Service

This direct load control program reduces PEF'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. PEF 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 PEF'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. PEF 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 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. PEF will collaborate with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system will be provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This program represents an updated version of the previous residential Renewable Energy Program. It 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 will 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 PEF 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 PEF 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 PEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in PEF 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 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

Progress Energy

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2012 PEF had a summer total capacity resource of 12,092 MW (see Table 3.1). This capacity resource includes nuclear (in February 2013 PEF announced the retirement of CR3, 789 MW), fossil steam (3,431 MW), combined-cycle plants (3,191 MW), combustion turbines (2,473 MW; 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (412 MW), independent power purchases (1,113 MW), and non-utility purchased power (683 MW). Table 3.2 presents PEF'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

PEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. PEF'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 PEF. In its planning process, PEF 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

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This plan includes the retirement of Crystal River 3 in 2013, expected retirement of Crystal River 1 & 2 in 2016, planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 and 2020 at undesignated sites. The addition of Levy Unit 1 and Unit 2 are not included in this ten-year planning horizon but have planned in-service dates of 2024 and 2025, respectively. These additions 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 PEF's Base Expansion Plan.

PEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2013 through 2022. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the PEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by PEF'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. Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with PEF Bulk Electric System (BES) are shown in Schedule 10.

PEF announced the retirement of Crystal River Unit 3 effective January 31, 2013. This has been reflected in this TYSP.

The promulgation of the Mercury and Air Toxics Standards (MATS) by EPA in April of 2012 presents new environmental requirements for the PEF 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.
- PEF has begun a project at the Anclote facility to convert the two residual oil fired units there to 100% firing on natural gas. This project is expected to be complete by early second quarter of 2014. The project will result in no change to the output of the two units.

- NOx and SO_2 control equipment was added to Units 4 and 5 at Crystal River in 2009 and 2010. These environmental control upgrades are expected to enable these two units to operate in compliance with the requirements of the MATS, but PEF is conducting tests to confirm expected 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, subject to approval of 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. PEF anticipates retiring these units prior to 2020.
    - In this TYSP, PEF anticipates retiring these units in April of 2016 following the receipt of a one year MATS compliance extension from the Florida Department of Environmental Protection due to the need to make transmission grid upgrades to maintain reliability. PEF continues to evaluate alternatives that would allow these units to operate in compliance with MATS during the period 2015 – 2020.

Additional details regarding PEF's compliance strategies in response to the MATS rule are provided in PEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI.

PEF 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. The Suwannee units are anticipated to have their operational lives extended to the spring of 2018. The other units continue to show anticipated retirement dates in 2016.

Given the retirements and anticipated retirements discussed above, particularly at the Crystal River Energy Complex, along with expected load growth, PEF is preparing to add additional resources in the period beginning in 2016.

- PEF is currently negotiating with a number of counterparties including cogenerators, independent power producers and neighboring utilities to purchase energy and firm capacity to supplement PEF's current owned generation and contracted resources. Based on PEF's current projected needs, these contracts will vary in capacity and length, projected to be principally 2, 4 and 5 year contracts. Anticipated energy and capacity supplied by these contracts are reflected in this TYSP. Specific counterparties are not identified as commercial negotiations are ongoing.

- PEF is preparing for the addition of two new combined cycle units, one in service beginning in 2018 and the other in 2020. Early development of the 2018 unit including site selection and preliminary engineering is currently underway. A preferred site for this unit has not yet been selected and thus is not reflected in Chapter 4.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2012

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	789	*(1)*
Total Nuclear Steam	1	789	
Fossil Steam			
Crystal River	4	2,291	
Anclote	2	1,011	
Suwannee River	3	129	
Total Fossil Steam	9	3,431	
Combined Cycle			
Bartow	1	1,074	
Hines Energy Complex	4	1,912	
Tiger Bay	1	205	
Total Combined cycle	6	3,191	
Combustion Turbine			
DeBary	10	636	
Intercession City	14	986	*(2)*
Bayboro	4	174	
Bartow	4	177	
Suwannee	3	155	
Turner	4	134	
Higgins	4	105	
Avon Park	2	48	
University of Florida	1	46	
Rio Pinar	1	12	
Total Combustion Turbine	47	2,473	
Total Units	**63**		
Total Net Generating Capability		**9,884**	

(1) Adjusted for sale of approximately 8.2% of total capacity

(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power		
Firm Qualifying Facility Contracts	13	683
Investor Owned Utilities	2	412
Independent Power Producers	2	1,113
TOTAL CAPACITY RESOURCES		**12,092**

TABLE 3.2

**PROGRESS ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS**

AS OF DECEMBER 31, 2012

Facility Name	Firm Capacity (MW)
Dade County Resource Recovery	43
El Dorado	114.2
Lake Cogen	110
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
TOTAL	**682.6**

PROGRESS 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
2013	8,952	1,926	0	173	11,052	8,965	2,087	23%	0	2,087	23%
2014	8,952	1,831	0	177	10,960	9,026	1,935	21%	0	1,935	21%
2015	8,952	1,871	0	177	11,000	9,185	1,816	20%	0	1,816	20%
2016	7,898	3,340	0	177	11,415	9,442	1,974	21%	0	1,974	21%
2017	7,898	3,340	0	177	11,415	9,504	1,911	20%	0	1,911	20%
2018	8,958	2,840	0	177	11,975	9,674	2,301	24%	0	2,301	24%
2019	8,958	2,840	0	177	11,975	9,846	2,129	22%	0	2,129	22%
2020	10,147	1,860	0	177	12,185	10,017	2,168	22%	0	2,168	22%
2021	10,147	1,860	0	177	12,185	10,086	2,099	21%	0	2,099	21%
2022	10,334	1,860	0	177	12,371	10,252	2,119	21%	0	2,119	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

PROGRESS 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
2012/13	10,996	2,121	0	173	13,290	8,987	4,303	48%	805	3,498	39%
2013/14	10,191	1,915	0	190	12,297	9,090	3,207	35%	0	3,207	35%
2014/15	10,191	1,915	0	177	12,284	9,710	2,574	27%	0	2,574	27%
2015/16	10,191	1,945	0	177	12,314	9,842	2,472	25%	0	2,472	25%
2016/17	9,089	3,424	0	177	12,691	9,910	2,781	28%	0	2,781	28%
2017/18	9,089	3,424	0	177	12,691	10,036	2,655	26%	0	2,655	26%
2018/19	10,265	2,924	0	177	13,366	10,188	3,178	31%	0	3,178	31%
2019/20	10,265	2,924	0	177	13,366	10,335	3,031	29%	0	3,031	29%
2020/21	11,571	1,944	0	177	13,693	10,485	3,208	31%	0	3,208	31%
2021/22	11,571	1,944	0	177	13,693	10,635	3,058	29%	0	3,058	29%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

PROGRESS ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2013 THROUGH DECEMBER 31, 2022

(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[b]	NOTES[c]
CRYSTAL RIVER	3	CITRUS	NP	BIT		RR	WA		10/1966	1/2013		(789)	(805)	RT	(1)
ANCLOTE	1	PASCO	ST	NG		PL			4/2013			0	0	FC	(1)
ANCLOTE	2	PASCO	ST	NG		PL			12 2013			0	0	FC	(1)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/1966	4/2016		(370)	(372)	RT	(1)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/1969	4/2016		(499)	(503)	RT	(1)
HIGGINS	P1-4	PINELLAS	GT							d.		(105)	(116)	P	(1)
TURNER	P1-2	VOLUSIA	GT							d.		(20)	(26)	P	(1)
AVON PARK	P1-2	HIGHLANDS	GT							d.		(48)	(70)	P	(1)
RIO PINAR	P1	ORANGE	GT							d.		(12)	(15)	P	(1)
SUWANNEE RIVER	1-3	SUWANNEE	ST							e		(129)	(131)	P	(1)
UNKNOWN	1	UNKNOWN	CC					01/2015	06/2018			1189	1307	P	(1)
UNKNOWN	2	UNKNOWN	CC					01/2017	06/2020			1189	1307	P	(1)
UNKNOWN	1	UNKNOWN	CT					06/2020	06/2022			187	214	P	(1)

a. Net capability of Crystal River 3 represents approximately 91.8% PEF Ownership.
b. See page v. for Code Legend of Future Generating Unit Status.
c. NOTES
(1) Planned, Prospective, or Committed project.
d. Higgins P1-4, Turner P1-2, Avon Park P1-2, Rio Pinar P1 are expected to be shut down by 6/2016.
e. Suwannee 1-3 are expected to be shut down by 5/2018.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:		**Undesignated CC1**	
(2)	Capacity			
	a. Summer:		1189	
	b. Winter:		1307	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2015	
	b. Commercial in-service date:		6/2018	(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 (%):		86.1	%
	e. Average Net Operating Heat Rate (ANOHR):		6,703	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		25	
	b. Total Installed Cost (In-service year $/kW):		1,403.25	
	c. Direct Construction Cost ($/kW):	($2013)	1,181.33	
	d. AFUDC Amount ($/kW):		127.95	
	e. Escalation ($/kW):		93.97	
	f. Fixed O&M ($/kW-yr):	($2013)	4.89	
	g. Variable O&M ($/MWh):	($2013)	4.19	
	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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:		**Undesignated CC2**	
(2)	Capacity			
	a. Summer:		1189	
	b. Winter:		1307	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2017	
	b. Commercial in-service date:		6/2020	(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 (%):		81.5 %	
	e. Average Net Operating Heat Rate (ANOHR):		6,720 BTU/kWh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		25	
	b. Total Installed Cost (In-service year $/kW):		1,066.64	
	c. Direct Construction Cost ($/kW):	($2013)	858.74	
	d. AFUDC Amount ($/kW):		97.53	
	e. Escalation ($/kW):		110.37	
	f. Fixed O&M ($/kW-yr):	($2013)	1.84	
	g. Variable O&M ($/MWh):	($2013)	4.19	
	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

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:	**Undesignated CT1**	
(2)	Capacity		
	a. Summer:	187	
	b. Winter:	214	
(3)	Technology Type:	SIMPLE CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	1/2020	
	b. Commercial in-service date:	6/2022	(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:	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):	3.85	%
	b. Forced Outage Factor (FOF):	2.05	%
	c. Equivalent Availability Factor (EAF):	94.18	%
	d. Resulting Capacity Factor (%):	10.9	%
	e. Average Net Operating Heat Rate (ANOHR):	10,649	BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	715.02	
	c. Direct Construction Cost ($/kW): ($2013)	567.83	
	d. AFUDC Amount ($/kW):	30.95	
	e. Escalation ($/kW):	116.24	
	f. Fixed O&M ($/kW-yr): ($2013)	3.00	
	g. Variable O&M ($/MWh): ($2013)	10.13	
	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

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

PEF has not designiated a site for this CC1, CC2 or CT1 in Schedule 8 and therefore does not have any Directly Associated Lines with these units.

INTEGRATED RESOURCE PLANNING OVERVIEW

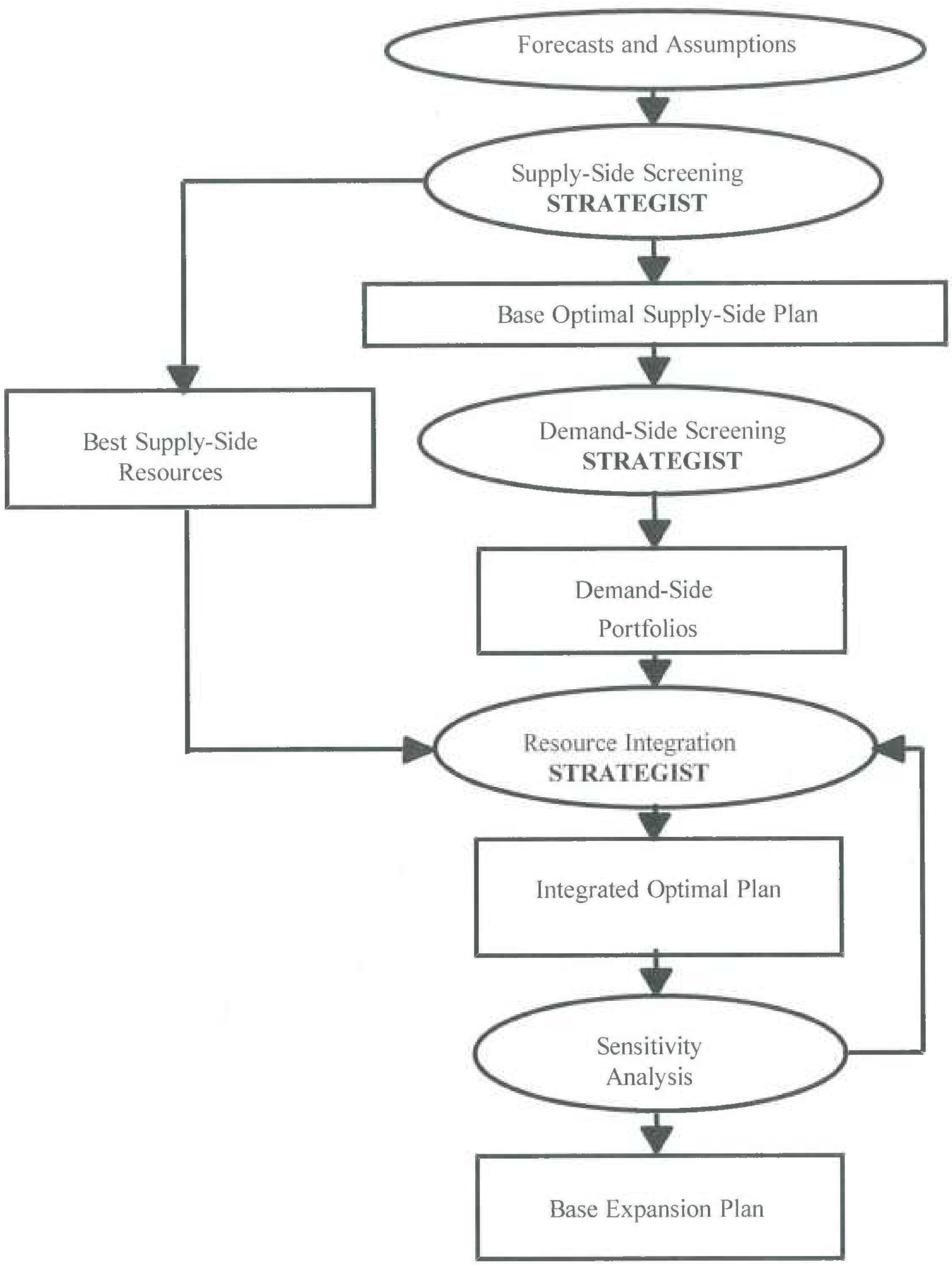
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of PEF'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 PEF 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 PEF 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 PEF'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 PEF'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.

PEF 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 PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF 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 PEF, is a maximum of one day in ten years loss of load probability.

PEF 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. PEF'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, PEF'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. PEF 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 PEF'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 PEF'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 PEF'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 PEF 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 PEF's most recent planning studies were 47 percent debt and 53 percent equity capital structure, projected cost of debt of 3.05 percent, and an equity return of 10.5 percent. The assumptions resulted on a weighted average cost of capital of 7.00 percent and an after-tax discount rate of 6.47 percent.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

The planned units in this TYSP result in a robust plan that includes the retirement of the Crystal River Nuclear Unit No. 3 in January 2013, retirement of Crystal River Units 1 & 2 in 2016, the installation of combined cycle units in 2018 and 2020 at locations that has not yet been chosen, as well as purchases in years 2016 through 2020. Levy Units 1 & 2 are beyond this ten-year planning horizon but are planned for the years 2024 and 2025, respectively. Additionally, PEF anticipates the retirements of older, smaller combustion turbines and steam units in the year 2016 and 2018, respectively.

Through its ongoing planning process, PEF 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, and 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

PEF continues to make purchases from the following facilities listed by fuel type:

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 MW)

Metro-Dade County Resource Recovery (43 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

PEF owned installations (approximately 930 kW)

PEF's Net Metering Tariff includes over 12.5 MW of solar PV

In addition, PEF has contracts with U.S. EcoGen (60 MW), TransWorld Energy (40 MW), and FB Energy (60 MW). U.S. Ecogen will utilize an energy crop, while the FB Energy facility and the TransWorld Energy facility will utilize wood products as their fuel source.

PEF 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	
Metro-Dade Resource Recovery	43	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	
FB Energy	60	No	12/1/13
U.S. EcoGen Polk	60	No	1/1/14

Trans World Energy	40	No	7/1/13
PEF 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.

PEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. PEF continues to keep an open Request for Renewables (RFR) soliciting proposals for renewable energy projects. PEF's open RFR continues to receive interest and to date has logged over 310 responses. PEF 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 PEF'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

PEF'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 PEF, 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. PEF 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, 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 PEF 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.

PEF 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.docx.

- http://www.oatioasis.com/FPC/FPCdocs/TRMID.docx

PEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID.docx

PEF proposed bulk transmission line additions are summarized in the following Table 3.3. PEF has listed only the larger transmission projects. These projects may change depending upon the outcome of PEF's final corridor and specific route selection process.

TABLE 3.3
PROGRESS ENERGY FLORIDA
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2013 - 2022

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1370	PEF	INTERCESSION CITY	Gifford	13	5/31/2013	230
1000	PEF	KATHLEEN	ZEPHYRHILLS N	12	5/31/2013	230

ATTACHMENT C
Response Package (Instructions)

10-8-13

DEF2018RFP

Attachment C - Response Package
TABLE OF CONTENTS

I. General Instructions

This Response Package contains the information required of Bidders and reviews the required organizational structure and contents of the proposals submitted in response to DEF's RFP for Power Supply Resources. Prior to developing their proposals, Bidders are requested to carefully read Duke Energy Florida's RFP and the instructions in this Response Package.

DEF will be utilizing PowerAdvocate (www.PowerAdvocate.com for further basic information on PowerAdvocate) RFP web tool to download, communicate and upload RFP information. There are no associated charges or specific registration restrictions associated with the registration process. In order to download the DEF 2018 RFP, an interested party must register with PowerAdvocate as a user to access their site which will require basic registration information. To access the DEF 2018 RFP registration process the following link should be used:

www.duke-energy.com/floridarfp

In most cases, the confirmation and acceptance of the registration process should occur within 1 to 4 hours, or within an 8 hr business day window, and an associate email with a link to access the DEF 2018 RFP information will be sent to the user.

Proposals in response to this RFP must be submitted in electronic version via the PowerAdvocate RFP web tool. Additionally, a copied version of the submitted proposal in electronic format and provided on a flash-drive should be delivered to the IM/E at the Sedway Consulting address listed for the Official Contacts in I.E. no later than one day after the DEF December 9, 2013 deadline, or by December 10, 2013. Text portions of the responses must be in Microsoft Word or Adobe Acrobat and schedules are in Microsoft Excel. Preprinted materials such as maps, annual reports, etc. should be submitted in electronic format through the website as well. Bidders must ensure that the proposals are delivered on time.

The PowerAdvocate web site is designed for bidders to upload their complete response package associated with each bid utilizing the three basic tab categories designated by PowerAdvocate as Commercial, Technical and Pricing. Please note the tab names are generic PowerAdvocate tab names and each tab may include various aspects of information relating to technical or pricing information without restrictions to the tab name.

Specific individual bid responses should be uploaded to these three tabs (Commercial, Technical and Pricing) as follows:

(1) **Commercial (or the Commercial tab)[Word Type Files]:** All word related text documents should be uploaded to the commercial tab. Basically, this will consist of the Bidders text responses to Chapters (Executive Summary and Chapters 1 through 12) as one Word document (not individual chapter documents).

(2) **Technical (or the Technical tab)[Non-Word or Non-Excel Files]:** All non-Word or non-Excel files such as .pdf or .jpg should be uploaded to the Technical tab. Basically, this will

consist of the Bidders' referenced information from the Word or Excel files which are cumbersome to include within those Word or Excel files.

(3) **Pricing (or Pricing tab)[excel Type Files]:** All Excel file documents should be uploaded to the Pricing tab. Basically, this will consist of one Excel File with the nine associated RFP schedules as tabs within the Excel file.

Submissions on flash-drives also should be structured in three folders in accordance with the above.

Bidders are required to use the schedules provided. The schedules (as well as the format of the entire Response Package) have been designed to facilitate the evaluation of the proposals in an expedient manner. Failure to use the schedules will be grounds for disqualification.

II. Organization and Contents of Bidders' Proposals

A. Overview

Bidders' proposals **must** be organized according to the structure specified below. If a particular chapter or section is not relevant to a Bidder's proposal, then the Bidder should include the chapter or section and indicate why it is not relevant. Where DEF has included a schedule that is to be completed by the Bidder, the schedules must be completed or the Bidder must indicate why the schedule is not relevant. This requirement is in place to assist the Bidder and DEF in assuring that no question has been overlooked and to provide all relevant information needed to evaluate the proposals.

B. Proposal Outline

The outline that Bidders **must** use to organize their proposals is presented below. Also specified in each section of this Response Package are the chapter number and section number that should be used for all proposals. The specific information that is to be included in each chapter is described below. However, because the information requested may not be relevant to all types of proposals, DEF has indicated in bold the type of proposal to which each question applies. **Where no specific type of proposal is indicated, the Bidder should assume that the information is required for all types of proposals. The Executive Summary and Chapters 1 – 12 word documents should be uploaded to the Power Advocate Commercial tab (and included in the Commercial folder on flash-drive submissions) as one word document when completed.**

- Proposal Executive Summary
- Chapter 1: Project Summary
- Chapter 2: Proposal Pricing
- Chapter 3: Operating Performance
- Chapter 4: Permitting Plans
- Chapter 5: Engineering and Design Plans
- Chapter 6: Site Control
- Chapter 7: Transmission Plan
- Chapter 8: Fuel Supply and Transportation Plan
- Chapter 9: Project Financing Plan
- Chapter 10: Commercial Operation Date Certainty

- Chapter 11: Bidder Experience
- Chapter 12: Acceptance of key Terms & Conditions

This Response Package is organized around a series of schedules. The matrix presented below indicates which schedules apply to different types of proposals. These schedules are provided in an Excel workbook included as part of this Response Package. If a schedule applies to the type of proposal that the Bidder is submitting, the Bidder is **required** to complete the schedule. **Inconsistencies between the electronic and hard copies will be grounds for disqualification. The Excel File with the associated Schedule A tab and 1 – 9 schedules should be uploaded to the Power Advocate Commercial tab as one Excel document when completed.**

Schedules To Be Completed By Bidder

Schedule No. and Name	New Unit	Existing Unit	System Power
Schedule A: Project Summary	X	X	X
Schedule 1: Pricing Schedule for New and Existing Unit Proposals	X	X	
Schedule 2: Pricing Schedule for System Power Proposals			X
Schedule 3: Capacity States and Heat Rates for New and Existing Unit Proposals	X	X	
Schedule 4: Operating Performance Schedule	X	X	X
Schedule 5: Environmental and Regulatory Permit Status Schedule	X		
Schedule 6: Air Emissions Schedule	X	X	
Schedule 7: Transmission Information Schedule	X	X	X
Schedule 8: Project Pro Forma Schedule	X		
Schedule 9: Project Milestone Schedule	X		

All other non Word or Excel files should be referenced to their associated Word or Excel file, uploaded to the Power Advocate Technical tab, and included in the Technical Folder in the flash-drive submissions.

C. *Proposal Executive Summary*

The Bidder is required to provide a brief summary of its proposal (no more than two pages). The summary should include at a minimum a brief overview of the technology and equipment proposed, amount of capacity offered, project location and point of delivery, proposed project pricing, power delivery period, proposed fuel supply arrangements, experience with key project elements, financing plan/arrangements, permitting schedule, and conformance with the key Terms & Conditions (reference Attachment A to the RFP).

D. *Chapter 1: Project Summary*

Chapter 1 of the Bidder's proposal must consist of a completed Project Summary (Schedule A). Bidders should complete Schedule A after they have completed all other schedules; data must be consistent with the detailed schedules. The information in this form will be treated as non-confidential and non-proprietary and may be released to the public.

E. Chapter 2: Proposal Pricing

Introduction

Bidders are required to complete all the applicable pricing schedules referenced in this chapter of the Response Package and to provide a complete description of the components of the charges. Duke Energy Florida has included price schedules for New and Existing Unit Proposals (Schedule 1) and System Power Proposals (Schedule 2) in the Response Package forms as part of this package. Bidders should only complete those schedules that are pertinent to the type of bid submitted (reference "Schedules to be Completed by Bidder" table on Page C2). Bidders should note that contract year one is a partial year. Therefore, a "15-year" contract will cover one partial year and fourteen full years, for example, May 1, 2018 through December 31, 2032.

Price Schedule for New and Existing Unit Proposals

Bidders offering New or Existing Unit Proposals must complete all relevant sections of Schedule 1 as described in this section of the Response Package. Bidders should ensure that the pricing components of their proposals conform to the requirements described in Figure III-3 (New and Existing Unit Proposal Pricing Parameters) of the DEF 2018 RFP Document. **All costs to be paid by DEF must be reflected in the proposed pricing. DEF will not accept any charges other than those identified in Schedule 1.** Bidders must specify the pricing for their proposals in terms of the following components and units, to the degree that each component is relevant to the particular bid:

- Fixed Payment
  - Generation Capital Charge ($/kW-Yr)
  - Fixed Operation and Maintenance (O&M) Charge ($/kW-Yr)
  - Transmission Charge ($/kW-Yr)
  - Pipeline Reservation Charge ($/mmBtu-day)
- Variable Payment
  - Fuel Commodity ($/mmBtu)
  - Variable Transportation ($/mmBtu)
  - Variable O&M Price ($/MWh, $/hour, or both)
- Start Payment
  - Start Price Per Facility ($/start/facility).

In addition to completing the schedule, Bidders should include back-up sheets that clearly describe their pricing proposals in terms of the pricing components, any indices proposed to adjust the prices, and the frequency of change in the indices for payment purposes.

The first entries in Schedule 1 are the Contract Start Month, the Contract Start Year, and the Contract End Year, which represent the term for which capacity and energy will be provided to DEF by the Bidder. Bidders must then specify the proposed Contract Capacity for both the Winter and Summer Seasons for each year of the proposed term.

CAPACITY SPECIFICATION CRITERIA

- Summer: 90ºF, 60% R.H.
- Winter: 40ºF, 60% R.H.

SEASONAL DEFINITIONS

Summer	Winter
May through October	November through April

Bidders then enter the annual fixed payment items in Schedule 1 for every year of the term of the proposal. The annual fixed payments must be based on the Seasonal Contract Capacities. Therefore, Bidders must take into account the difference in Summer and Winter Contract Capacities and enter **annualized** $/kW values for every year, including the start year when the proposal does not include all 12 months of the calendar year. Since the Summer and Winter Periods each contain six (6) months, this can easily be achieved by using the average Summer and Winter Contract Capacities when developing $/kW values. Bidders will be paid monthly based on the product of the Bidder-specified seasonal capacity and one-twelfth (1/12) of the Bidder-specified annual charges, and will be subject to adjustments based on actual operating performance (the adjustments for operating performance are described in the key Terms & Conditions included as Attachment A to the DEF 2018 RFP Document).

Generation capital charges are to be consistent with the generation equipment costs specified in Section 9.0 of the Bidder's proposal. Fixed O&M charges should reflect the fixed costs associated with operating and maintaining the project.

A transmission charge must be specified by the Bidder in Schedule 1 for each year of the proposal. These charges should represent the Bidder's Interconnection Facilities and wheeling (if applicable) costs to DEF's Delivery Point and must be based on the Seasonal Contract Capacities. The transmission charges specified are to be consistent with the transmission equipment costs specified in Section 9.0 of the Bidder's proposal. If the proposed project is not located in the DEF system, any costs related to an upgrade of other transmission systems required for delivery of Firm Power from the Facility to the delivery point in the DEF system must be included in the price proposal by the Bidder. Costs for any necessary upgrades to integrate the project into the DEF transmission system will be estimated by DEF during the Initial Detailed and Final Detailed Evaluations of proposals and the costs for the upgrades on the DEF system and other affected utility systems will be included in the evaluation of the proposal.

Bidders must specify a fixed pipeline demand/reservation charge (if appropriate to the technology being proposed). Bidders must specify a charge for each year of the proposal in $/mmBtu-day and must specify the amount of transportation proposed to be reserved (in Chapter 8 of the proposal). Bidders may specify a fixed pipeline demand/reservation tariff as the price. DEF reserves the right to negotiate fuel transportation provisions with the Bidder if benefits can be derived for DEF and its customers.

Bidders must provide fuel price proposals for the primary and secondary fuels. The primary fuel is the fuel that the Bidder expects to use for the majority of the generation in the year, and the secondary fuel is the fuel that the Bidder expects to use for the remaining generation. If desired, the Bidder may propose to use only one fuel throughout the year and not specify a secondary fuel (the primary and secondary fuels are specified on Schedule A). Bidders have three options for proposing fuel prices:

1. the Bidder may specify a series of firm prices or a price that escalates at a Bidder-specified rate. These prices will be used for evaluation and payment purposes. The escalation rate used must be outlined in the Bidder's proposal.
2. the Bidder may propose to use a price index or combination of indices or propose a formula based on an index or combination of indices. Reference price forecasts are provided in Schedule 1 for the Bidder to use as an index to formulate prices. The Bidder should enter the formula in the appropriate cells (in Rows 29-30 and 32-33 of Schedule 1) and also describe the formula in Chapter 2 of its proposal. The Bidder shall enter the name of the proposed index (e.g., "Gas Daily Henry Hub", "Gas Daily Florida Citygate", etc.) in the space provided on Rows 48 and 49 of Schedule 1.
3. the Bidder may propose to use a fuel tolling arrangement whereby DEF will supply fuel tolling services to the project. If the Bidder selects this option, DEF will determine the appropriate price to use for the evaluation.

If the Bidder selects option 2 above, the DEF fuel price forecast will be used as an index to evaluate proposals; however, the Bidder will be paid based on the actual values of the index(es) at the time of payment. The DEF fuel price forecast assumptions are based on recent forecasts for the fuels; however, DEF reserves the right to update these forecasts during the evaluation period if they no longer reflect DEF's current expectations.

The index selected for each pricing component should be consistent with market-based indices that are appropriate for that component. For example, if a Bidder proposes to use natural gas as its primary fuel, a gas commodity index is appropriate to choose. If a Bidder proposes to use a secondary fuel, the Bidder should select an appropriate index for that fuel. The Bidder must identify the pricing point for the index selected, if appropriate.

Bidders must enter annual prices for variable O&M. Although Bidders may specify two fuels (Primary and Secondary) to be used during a year, Bidders should enter only one annual price for each of the O&M components. These prices should reflect the weighted average annual O&M, based on the proposed fuels. Bidders may propose variable O&M prices in terms of $/MWh or $/hour of operation, or both.

Bidders are also required to enter annual start prices. The start price component is designed to compensate the Bidder for the cost of starting the Facility. Payment will only be made for starts required and initiated by DEF. DEF will not reimburse the Bidder for test starts or starts arising from a forced outage or from an unplanned maintenance outage. DEF will estimate the number of starts for evaluation purposes but pay the Bidder based on the actual number of successful starts.

Schedule 1 provides an area for other costs to be specified by the Bidder. Any other costs the Bidder expects DEF to pay must be identified in this area. **DEF will not accept any charges other than those identified in Schedule 1.**

Bidders should include back-up sheets which clearly describe their pricing proposals in terms of the pricing components and the index(es) proposed to adjust the prices.

Price Schedule For System Power Proposals

Bidders who are proposing System Power Proposals are required to complete Schedule 2. **All costs to be paid by DEF must be reflected in the proposed pricing. DEF will not accept any charges other than those identified in Schedule 2.**

The first entries in Schedule 2 are the Contract Start Month, the Contract Start Year, and the Contract End Year, which represent the term for which capacity and energy will be provided to DEF by the Bidder. Bidders must then specify the proposed Contract Capacity for both the winter and Summer Seasons for each year of the proposed term.

Bidders next enter capacity and transmission charges, fuel and non-fuel energy prices, and start prices in Schedule 2 for every year of the term of the proposal. The capacity charge should represent fixed costs associated with the generation system from which power is being provided. For the transmission charge, the Bidder should enter the total price of transmission, including wheeling and system upgrade costs as appropriate, to deliver the system power to the delivery point at the DEF system. Costs for any necessary upgrades to integrate the proposed power flow into the DEF transmission system will be estimated by DEF during the Initial and Detailed Evaluations of proposals, and the costs for the upgrades on the DEF system and other affected utility systems will be included in the evaluation of the proposal.

The capacity and transmission charges must be based on the Seasonal Contract Capacities and must be entered as **annualized** values for every year, including the start year when the proposal does not include all twelve months of the calendar year. Bidders will be paid monthly based on the product of the Seasonal Contract Capacity and one-twelfth (1/12) of the Bidder-specified annual capacity and transmission charges, and will be subject to adjustments based on the actual availability of capacity under the agreement.

Bidders of System Power Proposals must guarantee 100% availability for the capacity and energy offered to DEF. In the event that DEF signs a power purchase agreement (PPA) with a Bidder to supply System Power, and that supplier fails to deliver the capacity and energy committed to in the PPA, then DEF will only pay for the capacity and energy actually received and will also charge the supplier for DEF's cost of replacement capacity and energy. DEF prefers proposals that, when curtailments are necessary, the Bidder curtails delivery only on a pro-rata basis simultaneously and proportionately along with the Bidder's other firm sales, including primary public service obligations.

The system fuel energy price should reflect the fuel costs associated with providing energy from the Bidder's generation system. Bidders have three options for proposing fuel-related system energy prices:

1. the Bidder may specify a series of firm prices or a price that escalates at a Bidder-specified rate. These prices will be used for evaluation and payment purposes. The escalation rate used by the Bidder must be outlined in the Bidder's proposal.
2. the Bidder may propose to use a price index or combination of indices or propose a formula based on an index or combination of indices. Reference price forecasts are provided in

Schedule 2 for the Bidder to use as an index to formulate prices. The Bidder should enter the formula in the appropriate cells (in Row 27 of Schedule 2) and also describe the formula in Chapter 2 of its proposal. The Bidder shall enter the proposed index(es) (e.g., "Gas Daily Henry Hub", "Gas Daily Florida Citygate", etc.) in the space provided on Row 40 of Schedule 2.

3. the Bidder may propose a "true-up" arrangement whereby the fuel price will be trued-up to the Bidder's regulatory jurisdiction's system average fuel price. If the Bidder selects this option, the bidder must provide a series of prices to be used for evaluation purposes, as well as evidence that the series of prices are reasonable.

If the Bidder selects option 2 above, the DEF fuel price forecast will be used as an index to evaluate the proposal; however, the Bidder will be paid based on the actual values of the index(es) at the time of payment. The DEF fuel price forecast assumptions are based on recent forecasts for the fuels; however, DEF reserves the right to update these forecasts during the evaluation period if they no longer reflect DEF's current expectations.

The index selected for each pricing component should be consistent with market-based indices that are appropriate for that component. For example, if a Bidder proposes to use natural gas as its primary fuel, a gas commodity index is appropriate to choose. If a Bidder proposes to use a secondary fuel, the Bidder should select an appropriate index for that fuel. The Bidder must identify the pricing point for the index selected, if appropriate.

The non-fuel energy costs should represent the non-fuel variable costs associated with providing energy from the Bidder's system. The non-fuel energy costs can be represented in terms of $/MWh or $/hour scheduled, or both.

The Bidder may also provide annual start prices. The start price component is designed to compensate the Bidder for the cost of starting various facilities when DEF schedules power for delivery. DEF will estimate the number of starts for evaluation purposes but pay the Bidder based on the actual number of times DEF schedules power for delivery.

Schedule 2 provides an area for other costs to be specified by the Bidder. Any other costs the Bidder expects DEF to pay must be identified in this area. **DEF will not accept any charges other than those identified in Schedule 2.**

Bidders should include back-up sheets which clearly describe their pricing proposals in terms of the pricing components and the index(es) proposed to adjust the prices.

Contract Flexibility Provisions

Also pursuant to Section II.E of the DEF 2018 RFP Document, DEF is encouraging Bidders to offer contract flexibility provisions. For example, Bidders may propose an initial contract term and provide DEF options to extend the term at predefined prices. If Bidders would like to provide such options, the pricing schedules should be used to convey the prices. The initial term should be entered as the Contract Term, and the extension provisions should be explained by the Bidder. Other flexibility provisions could also be proposed. Bidders should clearly and completely explain their proposals, including appropriate pricing information.

F. Chapter 3: Operating Performance

In this chapter of its proposal, each Bidder must demonstrate how its proposal complies with all of the operating performance requirements specified in Section III of the DEF 2018 RFP Document and the degree to which it is consistent with DEF's preferences for the operational Technical Criteria outlined in Section III.B.3.b.ii of the RFP. In Attachment A of the DEF 2018 RFP Document, DEF has provided key Terms & Conditions that provide several of the key operating performance requirements which will be used to ensure that the Bidder's generating resource provides DEF with its required level of operating performance. Bidders are required to answer the questions presented in Schedules 3 and 4 and to provide all necessary data to support the answers provided.

Bidders must specify in Schedule 3 the proposed project's heat rate information for the proposed primary fuel and secondary fuel. The heat rate data must be provided by specifying seasonal capacity states and heat rates for each fuel based on the Capacity Specification Criteria and Seasonal Capacity Specification Criteria provided in Attachment A (key Terms & Conditions). <u>Capacity states must be specified at net generation levels at the delivery point of the DEF system.</u> In addition, the Bidder should specify the elevation at which the unit is (would be) be sited. The heat rate data provided will be used for both evaluation and contract purposes.

Heat rates must be expressed in terms of the higher heating value of the fuel and must be the average (not incremental) heat rate for the capacity state. Heat rates must incorporate any margin for degradation during the term of the contract. Degradation may be incorporated over the term or annually. Bidders are required to provide heat rate data for the minimum load and full load operating points (the full load capacity values must be equal to the Seasonal Contract Capacity values and are carried over from Schedule 1). Bidders may provide heat rates for up to three additional capacity states to better represent the operational characteristics of the proposed project.

In Schedule 4, the Bidder must provide responses to all items that apply to the type of proposal being offered. Answer yes or no for each Operating Performance threshold by entering an "X" in the appropriate box for each item in the first part of Schedule 4. In the second part of Schedule 4, Bidders must provide operating performance evaluation criteria responses and outage information.

G. Chapter 4: Permitting Plans

In this chapter of its proposal, each Bidder should demonstrate how its proposal complies with all of the permitting requirements specified in Section III of the RFP Solicitation Document, and the degree to which it is consistent with DEF's preferences for a high level of certainty that the proposed project will receive its required permits within the time indicated on the project's critical path schedule. Each Bidder is required to answer the questions presented below and provide all necessary data to support these answers. For sections that require responses to several bullet items, the Bidder must always precede its response with the bullet item, verbatim, as shown below.

<u>**Section**</u>

4.0 In Schedule 5, the Environmental and Regulatory Permit Status Schedule, identify which items would be required for the project to be constructed and operated by placing an "X" in the "Not Required" or "Required" column by each item. If a permit has been applied for, indicate the date that the permit was applied for in the column marked "Applied For" and the date that the permit is likely to be issued in the column labeled "Expected Receipt." Some of the required items are pre-printed in Schedule 5. However, if additional permits would be required, add them to the schedule in the blank cells provided.

The Bidder should indicate why the project is likely to receive each required permit, license, or approval. **[New Unit Proposals]**

4.1 Provide specific information for the project site as identified below. **[New Unit Proposals]**

- List any new rights-of-way required for the project for fuel pipelines, water pipelines, rail spurs, roadways, or electric transmission lines.
- Identify the total acreage of wetlands on the proposed site or rights-of-way before and after construction and the acreage disturbed, lost, or converted during construction.
- Provide a copy of a map showing any portions of the proposed site or rights-of-way that are in a local or state designated Coastal Zone Management Area (CZMA).
- Provide evidence that the existing zoning for the site is compatible with the proposed use and, if not, provide a plan for changing the zoning.
- Provide evidence that a Phase I Environmental Assessment has been completed and that the proposed site or rights-of-way are not contaminated. If the proposed site or rights-of-way are contaminated, indicate the clean-up measures planned, their estimated costs, schedules for completion, and status of reviews by appropriate federal or state agencies.
- Identify any environmentally sensitive areas (*i.e.*, wetlands, water use caution areas, state lands (including submerged), CZMA, wildlife refuge, public parks, critical habitats for endangered species) within a one-mile radius of the proposed plant location and any mitigation measures for these areas.
- Identify any sites of historical or archaeological significance within a one-mile radius of the proposed plant location and any mitigation measures for these areas.

4.2 Describe the current and recent past land use and development of the site and adjacent lands, discussing the compatibility of the project with adjacent and nearby land uses. **[New Unit Proposals]**

4.3 Provide a waste disposal plan for the proposed project which identifies the solid or hazardous wastes that would be generated by the project and identifies how they would be disposed. **[New Unit Proposals]**

4.4 Indicate the quantity and source of cooling, injection, steam make-up, and general use water that would be needed for the project. This information should include the characteristics of the water to be used, necessary treatment processes, and a discussion of competing uses for the water. Provide a water supply plan for securing water supply and delivery to the project. Include the source of the water, a description of the water delivery system, the terms and conditions of any existing water supply transportation arrangements, and the status of such arrangement. **[New Unit Proposals, Existing Unit Proposals]**

4.5 Provide the following information concerning the wastewater generated by the project **[New Unit Proposals]**:

- The sources, composition, and expected quantity of wastewater to be generated by the project, the disposal method to be employed, including any waste treatment methods, and the water composition after treatment.

- The classification of any surface waters or groundwaters to which wastewater effluent is discharged and the name of the surface water.

4.6 Describe any hydrologic alterations, (*e.g.*, dredging, filling, diking, outfall structure, or impoundment) of any surface waters that would be required by the project, identifying the affected resource, the significance of the alteration, and the mitigation measures proposed. **[New Unit Proposals]**

4.7 Provide the following information regarding the impact of the project on the air quality of the surrounding area **[New Unit Proposals, Existing Unit Proposals]**:

- Identify the air quality management area where the project is (would be) located and indicate the attainment status of this area for each of the criteria pollutants.

- Identify whether there are any Class 1 areas within 100 kilometers of the proposed project site. If so, indicate whether any visibility modeling has been performed and the visibility impacts on the Class 1 areas projected by the model.

- Indicate the removal efficiency of any pollution control equipment that is (would be) employed for NO_x, SO_2, PM, CO, Hg, or hazardous air pollutants (HAPs).

- Complete Schedule 6, the Air Emissions Schedule, for both the primary and secondary fuel.

- If BACT or LAER would apply to the project, indicate how the Bidder proposes to comply with these requirements.

- Describe plans for obtaining any required offsets and allowances for the project, including SO_2 and NO_x allowances.

- Address levels of NH_3 (ammonia) emissions and requirements for handling/storage, if used.

- Describe the strategy for compliance with the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR).

4.8 Indicate the expected incremental ambient noise level during the daytime and nighttime hours that would result from the operation of the project at the nearest property boundary and any planned mitigation measures. Also, indicate the distance of the nearest residence from the project and define the expected daytime and nighttime ambient noise levels at the nearest residence. **[New Unit Proposals]**

H. Chapter 5: Engineering and Design Plans

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the engineering and design requirements specified in Section III of the RFP Solicitation Document. The Bidder is required to provide the information requested below and all data necessary to support the answers provided. **[New Unit Proposals, Existing Unit Proposals]**

Section

5.0 This section is used to describe, at the highest level, the project's facilities. The discussion should clearly describe the assumptions as to what degree, if any, the new facilities will interface and rely on or enhance existing facilities.

- Layout and Location—Describe the location of the new facilities on site using a conceptual layout drawing. If existing facilities are present, show them in relation to the new units. The drawing(s) should show the location and size of the units and auxiliaries, stacks, fuel and water delivery systems, fuel and water storage tanks, waste water handling and disposal systems, water treatment systems, sanitary waste treatment systems, site storm water management systems, effluent storage system and tanks, etc. The site layout shall also identify wetland boundaries, buffers, etc. The drawing(s) should show the plant access for operations and construction, construction lay down and parking as well as security and buffer arrangements. The drawing(s) shall also show, in phantom, the location for future build-out reserve areas.

- Offices, Control Room, Shops and Warehousing—Describe what facilities are going to be built or added, either to existing or as standalone facilities. With regard to office and shop space, describe the number of individuals to be housed in offices, and the assumption on the level of maintenance work to be done in the shop.

- Transmission and Substation—Describe in general terms how the unit(s) are, or are proposed to be, interconnected to the Duke Energy Florida transmission system. Describe conceptually the substation arrangement (e.g. breaker and a half scheme) and at what voltage level the units are to be tied in to the substation. Describe the step up transformer including the MVA rating. Supply a single line diagram.

- 15 kV and Higher Equipment up to the Step up Transformer—Describe the 15kV equipment from the generator leads to the step up transformer. This description shall include the iso-phase bus work, generator breaker and connected auxiliary transformers and equipment. This equipment should be described on a single line diagram.

- Less than 15kV Electrical System—Describe the lesser voltage electrical systems to be installed. Indicate any interface or tie in to existing systems. Redundant systems should be defined. The uninterruptible power source for the plant shall also be described. Include appropriate single line diagrams.

- Plant Control Room Philosophy—Describe in general terms the overall control room philosophy as to the balance of plant DCS and the interface with the unit specific control system. Describe any tie-ins or interface with existing plant systems. Describe the interface of the DCS unit controls to the RTU connection to the DEF Energy Control Center.

- Raw, Service and Potable Water Facilities—Describe any new and/or existing facilities and any interconnection between the facilities, if applicable. The description shall include the capability of the systems and the storage requirements.

- Demineralized Water Facilities—Describe demineralized water facilities. Include the throughput and the amount of waste water to be rejected. Describe the storage facilities and the amount of capacity available in hours of operation. Describe the nature of the demineralizer arrangement as to whether it is leased and if it includes pre-filtration and reverse osmosis. If buildings are required describe them as well.

5.1 Provide an operations and maintenance plan (O&M Plan) which demonstrates that the project will be operated and maintained in a manner to allow the project to satisfy its contractual commitments. This O&M Plan should indicate proposed project staffing levels, the schedule for major maintenance activities, plans for inspecting and testing of major equipment, entities responsible for operating and maintaining the project, and status and schedule for securing a maintenance agreement.

5.2 Provide an engineering design plan that identifies the following:

- generation technology, including the make/model/supplier's name
- emission control equipment, including the make/model/supplier's name
- major equipment to be employed, including the make/model/supplier's name
- major equipment vendors
- whether new or refurbished equipment will be used
- commercial in-service date **[Existing Unit Proposals only]**

5.3 Provide historic operating performance data (heat rate, EFOR, summer and winter MDC, number of starts) for the proposed projects that demonstrate that they will be able to achieve the operating targets specified. **[Existing Unit Proposals only]**

Provide historic operating performance data (heat rate, EFOR, summer and winter MDC, number of starts) for projects of similar technology that demonstrate that the proposed technology will be able to achieve the operating targets specified. **[New Unit Proposal only]**

5.4 Provide a heat and material balance diagram.

5.5 Specify any limitations the proposed project will have regarding the start-up fuel system. If the project has or will have a secondary fuel, please specify whether the project will be able to start on either fuel independent of other fuel systems being completely out of service. Please specify whether the project will be able to switch fuel sources "on the fly."

5.6 Provide the following projected unit performance information:

- Equivalent Forced Outage Rate (EFOR)

  EFOR = [(FOH + EFDH)/(FOH + SH)]

  Where:

  FOH = Forced Outage Hours: The sum of all hours experienced during forced outages.

  EFDH = Equivalent Forced Derated Hours: The summation of the products of the Forced Derated Hours (FDH) and size (MW) of reduction for each event, divided by the Seasonal Contract Capacity (SCC).

  FDH = Forced Derated Hours: The number of hours experienced during a forced derated event.

  SH = Service Hours: The total number of hours a unit was electrically connected to the transmission system.

- Equivalent Availability Factor (EAF)

  EAF = [(AH - (EUDH + EPDH)) / PH]

  Where:

  AH = Available Hours: Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH) and Maintenance Outage Hours (MOH).

  PH = Period Hours: Number of hours in the period (month).

  POH = Planned Outage Hours: The sum of all hours experienced during planned outages and planned outage extensions.

  FOH = Forced Outage Hours: The sum of all hours experienced during forced outages.

  MOH = Maintenance Outage Hours: The sum of all hours experienced during maintenance outages and maintenance outage extensions.

  EUDH = Equivalent Unplanned Derated Hours: The summation of the products of Unplanned Derated Hours (UDH) and size (MW) of reduction for each event, divided by Seasonal Contract Capacity (SCC).

  UDH = Unplanned Derated Hours: The number of hours experienced during a forced derated event, a maintenance derated event, or scheduled derated extension of a maintenance derated event.

  EPDH = Equivalent Planned Derated Hours: The summation of the products of the Planned Derated Hours (PDH) and size (MW) of reduction for each event, divided by the Seasonal Contract Capacity (SCC).

  PDH = Planned Derated Hours: The number of hours experienced during planned derated event or scheduled derated extension of a planned derated event.

I. Chapter 6: Site Control

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the site control requirements specified in Section III of the RFP Solicitation Document. Bidders are required to provide the information requested below and all necessary data to support the answers provided. **[New Unit Proposals, Existing Unit Proposals]**

Section

6.0 Provide a USGS map (7.5 minute scale) that indicates the project site location and the surrounding area of at least two (2) miles from the site center, identifies all generation, substation, and other equipment, and all new rights-of-way that would be required for the project, including critical dimensions. Show proximity to and identify the nearest DEF substation and/or transmission line. Provide a recent aerial photograph showing the site location and surrounding area for at least one (1) mile from each site boundary.

6.1 Demonstrate site control either in the form of an agreement demonstrating ownership of the site, lease of the site for the term of the proposal, or at a minimum, an executed letter of intent to negotiate a lease for the site for the full contract term or term necessary for financing (whichever is greater) or to purchase the site. Provide a copy of a letter of intent or contract that demonstrates that the Bidder's proposal satisfies DEF's site control threshold. If the property is fee owned, a copy of the Title and Legal Description of the property is required.

6.2 If off-site rights-of-way are required for gas, electrical, water, or rail service, demonstrate site control either in the form of an executed letter of intent to negotiate a lease for the rights-of-way for the full contract term or term necessary for financing (whichever is greater) or to purchase the rights-of-way.

J. Chapter 7: Transmission Plan

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the transmission requirements specified in Section III of the RFP Solicitation Document. Bidders are required to provide the information requested below and all necessary data to support the answers provided .

Section

7.0 Bidders are required to provide a completed Transmission Information Schedule (Schedule 7). **[All Proposals]**

7.1 If the proposed project or power source is located outside of DEF's system, provide a transmission plan that identifies the project's proposed transmission path, including delivery point. Also provide evidence that the host system utility and all wheeling utilities are willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule the power from System Power Proposals. Identify the DEF interface utility that would be used to deliver the power to DEF. **[Existing Unit Proposals, New Unit Proposals]**

For New Unit Proposals located outside of the DEF system, bidders are required to provide one of the following from the host system utility:

- A Transmission System Impact study agreement from the host system's Transmission Provider that indicates that the output of the New Unit can be delivered to the DEF interface.
- Confirmed Transmission Service to the DEF interface

In addition, for New Unit Proposals located outside of the DEF system, bidders are required to provide the information in Schedule 7 of Attachment D.

- Bidders are required to provide the contact information of a transmission planner from the host system utility.

For Existing Unit Proposals located outside the DEF system, bidders are required to provide the information in Schedule 7 of Attachment D.

7.2 For projects located inside of the DEF system, bidders are required to the information in Schedule 7 of Attachment D.

K. Chapter 8: Fuel Supply and Transportation Plan

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the fuel supply and transportation plan requirements specified in Section III of the RFP Solicitation Document and the degree to which it is consistent with DEF's requirements for a reliable fuel supply for the proposed project. Bidders are required to provide a preliminary fuel supply plan and all necessary data to support the answers provided regarding this plan. **[New Unit Proposals, Existing Unit Proposals]** Bidders interested in having DEF provide fuel tolling services should complete Section 8.1 rather than Section 8.0.

Section
8.0 The preliminary fuel supply plan for both primary and secondary fuels must specify or provide the information listed below.

- Provide a map of the fuel supply and transportation infrastructure for the proposed project and a description of supply and transportation alternatives available to the project. If natural gas is proposed as a fuel (primary or secondary), identify the proposed main pipeline source, the length of any lateral from the main pipeline to the site, and the size and pressure of the lateral. If oil is proposed as a fuel (primary or secondary), provide the fuel quality requirements, proposed on-site storage capacity (total usable volume and number of tanks), the proposed transport means to the site, and the distance from the expected supply source.

- Provide copies of all fuel supply and transportation agreements in place for the proposed project. If fuel supply and transportation contracts are not in place, provide a description of the types and quality of service for fuel supply and transportation sought, the pricing and operational requirements, the contract terms and conditions required, and the status of such arrangements including the date that such arrangements will be in place. If the Bidder has received proposals from fuel and transportation providers, the Bidder should include the preferred proposal as well as a description of the experience of the Bidder in developing similar supply arrangements.

- Specify the criteria that would be used to select the ultimate fuel supplier and transportation service providers.

- If a secondary fuel is to be used, provide supporting information for the periods over which the primary and secondary fuel supply are expected to be used. The Bidder must specify any months in which the usage of the primary fuel is expected to be curtailed and the conditions under which the primary fuel is expected to be curtailed.

- Indicate whether transportation would be provided from existing capacity or whether new construction would be required. If new construction is required, provide an assessment of the availability of rights-of-way.

- If natural gas is being proposed, indicate the required gas pressure for the proposed project and confirm the capability of the pipeline to deliver natural gas to the project at or above that pressure.

- If natural gas is being proposed, indicate the amount of fixed pipeline demand/reservation (in mmBtu per day) on which the pricing is based.

- Describe the liquid fuel unloading facilities. This should include the number of truck or rail unloading stations and the unloading rate for the unloading facility. Describe the amount of existing storage and any new oil storage required. Describe if the storage is single or double walled and the amount of fuel oil storage dedicated to any new units. Describe whether a storage tank fire protection system is, or will be installed.

8.1 DEF is willing to consider tolling proposals. If the Bidder is interested in DEF providing fuel tolling services, the following information must be included in its proposal:

- Provide a map of the fuel supply and transportation infrastructure for the proposed project and a description of supply and transportation alternatives available to the project. If natural gas is proposed as a fuel (primary or secondary), identify the proposed main pipeline source, the length of any lateral from the main pipeline to the site, and the size and pressure of the lateral. If oil is proposed as a fuel (primary or secondary), provide the fuel quality requirements, proposed on-site storage capacity (total usable volume and number of tanks), the proposed transport means to the site, and the distance from the expected supply source.

- If a secondary fuel can be used, provide information for the periods over which the primary and secondary fuel supply is expected to be used.

[Existing Unit Proposals]

- The name of gas pipeline(s) with which the project is interconnected
- Location of the interconnection/meter
- Flow capability of each meter at the plant and the pressure requirement
- The name of the Operator Account
- Specify whether there are other units at the site that serve other customers such that a balancing agreement would need to be developed with a third party.

[New Unit Proposals]

- The name of gas pipeline(s) with which the project will be interconnected
- Location of the proposed interconnection/meter
- Specify whether the facility will serve only DEF such that the meter could be added to DEF's Operator Account.

L. Chapter 9: Project Financing Plan and Bidder Financial Information

The Bidder is required to provide evidence that the project is financially viable, that the project will likely be able to attract funds from investors, and that the Bidder has the financial ability to fulfill their obligations to DEF over the term of the contract. In this section of the proposal, the Bidder should demonstrate how its proposal complies with all of the project financial viability requirements specified in Section III of the RFP Solicitation Document and the degree to which it is consistent with DEF's preferences for proposals for which the Bidder is able to demonstrate that there is a high likelihood of the project securing funding. Bidders are required to provide the information requested below and all necessary data to support the answers provided.

Section

9.0 The financing plan must specify or provide the following: **[New Unit Proposals]**

- The projected cost of the project, broken down into the following major cost elements:

  Equipment
  - Generation facilities
  - Transmission Interconnection facilities
  - Fuel facilities (e.g. pipeline interconnection, oil storage tanks, rail spurs)

  EPC Contractor
  Contingency
  Licensing, permits and site certificates
  Interest During Construction
  Other Costs.

- How the proposed project would be financed, including likely lenders and investors, the terms under which funds would be provided, and the respective percentage of funding represented by debt and equity.

- The timing for securing financing.

- A description of the project from a legal and financial standpoint indicating the actual ownership structure, the entities that will have ownership interests and their percentage interests in the project, their responsibilities for the development of the project, and their responsibilities for funding of project development expenses.

- Provide documentation demonstrating the relevant experience of the Bidder (or partner responsible for securing financing) in obtaining financing for other power generation projects.

9.1 The Bidder is required to provide sufficient financial information to enable DEF to assess the financial strength and credit of the entity that would execute a contract with DEF. Bidders should provide information on their corporate structure (including identification of any parent companies), a copy of the respondent's most recent quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of respondent attesting to its accuracy, a copy of respondent's most recent annual report containing audited consolidated financial statements and a summary of respondent's relevant experience. Financial statements should include all associated footnotes. Financial statements, annual reports and other large documents may be referenced via a web site address. If the proposed contracting entity is not the same legal entity for which financial information is furnished, the respondent should state whether a parent guarantee will be provided to cover the obligations of the contracting entity.

9.2 The Bidder is required to include a discussion of the potential for increases or decreases in DEF's cost of capital and any competitive advantage the Bidder's financing arrangements may give the Bidder. **[All Proposals]**

9.3 For proposals that will be seeking to obtain project financing, Bidders are required to provide full project financial Pro Formas that supply, at a minimum, the information outlined in Schedule 8, Project Pro Formas Schedule, for the proposed financing term. For purposes of completing this pro forma, Bidders should assume an appropriate project capacity factor for the technology being proposed (10% for peaking duty, 50% for intermediate duty, and 80% for baseload duty). Actual project capacity factors will vary. The assumed capacity factor is used only to review the project's financial viability as indicated by the Bidder's project pro forma. DEF reserves the right to request project pro formas from all short-listed proposals. **[New Unit Proposals]**

M. Chapter 10: Commercial Operation Date Certainty

The Bidder is required to demonstrate that its New Unit Project will be able to achieve the commercial operation date requirements. As part of this demonstration, the Bidder is required to provide a critical path diagram and schedule for the project that conforms to the requirements specified below. DEF will evaluate the reasonableness of the following aspects of the Bidder's proposed schedule: permitting, securing the project site, fuel supply and transportation arrangements, engineering design, equipment procurement, project financing, project construction, and start-up and testing. DEF's evaluation will consider the evidence presented by the Bidder that the proposed schedule for each of these project elements is reasonable. For the purposes of developing this schedule only, the Bidder should assume that negotiations are finalized by August, 2014. However, specifying this date should not be construed as a commitment by DEF to finalize negotiations by this date.

Section

10.0 Provide a critical path diagram and schedule for the project that specifies the critical path for each of the elements of the project development cycle including but not limited to, the following: permitting, securing the project site, fuel supply and transportation arrangements, engineering design, equipment procurement, construction and permanent financing, project construction, and start-up and testing. **[New Unit Proposals]**

10.1 Complete Schedule 9, the Project Milestone Schedule, which will be included as part of an executed contract. **[New Unit Proposals]**

10.2 The Bidder should provide a summary of its current and planned electric power resources including such information as the source of supply, contract terms, and accessibility to the DEF system. For proposals that require new resources be built to maintain a reliable supply on the host system, Bidders are required to state the type of capacity to be built and provide evidence that the required construction can be completed in time to maintain a reliable supply. **[System Power Proposals]**

10.3 If the proposed project will be providing steam or electricity to a host customer, indicate the name of the entity to whom this service will be provided, the type and amount of energy to be provided, and the status of negotiations regarding the terms and conditions under which such service will be provided, including appropriate documentation of such contracts. **[New Unit Proposal, Existing Unit Proposal]**

N. Chapter 11: Bidder Experience

The Bidder is required to provide evidence regarding its relevant experience in developing projects that are of an equivalent size and technology. DEF will evaluate each Bidder's relevant experience in six areas: permitting, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. For proposals that rely on a project team composed of more than one firm to develop the project, the Bidder should indicate its relevant experience in working with other team members to develop projects.

Section

11.0 Provide for at least five comparable projects a project reference not affiliated with the Bidder. For each reference, specify a contact name, title, company, address, and phone number.

For each project, indicate the utility or company served and provide a description of the project, including project location, the size and type of project, the scheduled and actual in-service date, and the availability factor achieved. **[New Unit Proposals, Existing Unit Proposals]**

11.1 For each of the project participants, provide an experience statement which lists the relevant experience of the firm, including other projects of a similar type, size, and technology. Describe the experience in the following six areas: permitting, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. **[New Unit Proposals, Existing Unit Proposals]**

11.2 Provide documentation regarding the contractual relationship between the Bidder and all additional project participants and vendors. If this contractual relationship has not been finalized, specify the schedule for doing so. **[New Unit Proposals]**

11.3 Indicate if the Bidder has failed to perform under any contracts or agreements for power supplies. If so, please explain. **[All Proposals]**

11.4 Provide a summary of current litigation activity, with supporting explanatory information as necessary, related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services); (2) lease option arrangements for assets; (3) purchases of energy products and services (as above); or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.). **[All Proposals]**

O. Chapter 12: Acceptance of key Terms & Conditions

[All Proposals]
Attachment A to the DEF RFP Solicitation Document contains key Terms & Conditions that DEF will utilize during this RFP and any possible contract negotiations. The key Terms & Conditions were developed assuming the resources are in the DEF System.

Bidders willing to accept DEF's key Terms & Conditions (Attachment A to the DEF RFP Solicitation Document) without exceptions should indicate this in their proposals. Bidders with exceptions to the key Terms & Conditions should indicate all exceptions in red-lined form. Each exception should be clearly described and the requested change clearly identified. Bidders may provide the red-lined form using the Word version that was included in the RFP Package. Red-lined versions of the key Terms & Conditions should be accompanied by a textual discussion which provides the reason for the exception.

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

CHAPTER 4
ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's expansion plan beyond this TYSP planning horizon includes nuclear power at the Levy County greenfield site with the first unit planned for in 2024 and a second unit in 2025. PEF continues to evaluate available options for future supply alternatives. Appropriate permitting requirements for PEF's preferred Levy Site are discussed in the following site description.

LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

PEF has named a site in southern Levy County as the preferred location for construction of new generation. The Company is planning the construction of nuclear generation at this site with the first unit planned in 2024 and a second unit in 2025 which are both beyond the planning horizon for this TYSP.

The Levy County site (see Figures 4.1 a & b) is approximately 3,100 acres and located eight miles inland from the Gulf of Mexico and roughly ten miles north of the existing PEF Crystal River Energy Complex.

The site is about 2.5 miles from the Cross Florida Barge Canal, from which the Levy units may draw their makeup water to supply the on-site cooling water system. The Levy County Plant, together with the necessary associated site facilities, will occupy approximately ten percent of the 3,100 acre site and the remaining acreage will be preserved as an exclusionary boundary around the developed plant site and a buffer preserve. PEF purchased an additional 2,100 acre tract contiguous with the southern boundary of the Levy site that secures access to a water supply for the site from the Cross Florida Barge Canal as well as transmission corridors from the plant site. The property for many years had been used for cultivation of forest trees and was designated as Forestry/Rural Residential. The surrounding area land use is predominantly vacant, commercial forestry lands.

This site was chosen based on several considerations including availability of land and water resources, access to the electric transmission system, and environmental considerations. First, the Levy County site had access to an adequate water supply. Second, the site is at a relatively high elevation, which provides additional protection from wind damage and flooding. Third, unlike a number of other sites considered, the Levy site has more favorable geotechnical qualities, which are critical to siting a nuclear power plant. Fourth, the Levy site provides geographical separation from other electrical generating facilities. This site separation decreases the likelihood of a significant generation loss from a single event and a potential large-scale impact on the PEF system. The Levy County location also would assist in avoiding a potential loss from a single significant transmission system event that might result in a large-scale impact on the PEF system.

PEF's assessment of the Levy County site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site for nuclear generation units and related facilities. No significant issues were identified in PEF's evaluations of the property.

The Levy unit will be located on a greenfield site where site and transmission infrastructure must be constructed along with the buildings necessary for the power units. The site will include cooling towers, intake and discharge structures, containment buildings, auxiliary buildings, turbine buildings, diesel generators, warehouses, related site work and infrastructure, including roads, transmission lines, and a transmission substation. The proximity of the Levy County site to the PEF's existing Crystal River Site may provide opportunities for efficiencies in support functions with the existing Crystal River infrastructure. The Company submitted a Site Certification Application (SCA) to the Florida Department of Environmental Protection (FDEP) on June 2, 2008, for the entire site, including plants and associated facilities for the units. Site certification hearings were completed in March 2009, and the Siting Board approved the final certification in August 2009.

Nuclear power is a clean source of electric power generation. Electric power generation from nuclear fuel produces no sulfur dioxide (SO_2), nitrogen oxide (NO_x), green house gases (GHG), or other emissions. Therefore, it will have a positive effect on the surrounding air quality.

Water discharged from nuclear plants must meet federal Clean Water Act requirements and state water-quality standards. Before operating, a nuclear plant's licensing process requires an environmental impact statement that carefully examines and resolves all potential impacts to water quality from the operation of the plant. These issues include concerns about the discharge of waste water and the impacts on aquatic life in cooling water used by the plant.

Transmission modifications will be required to accommodate the Levy County Nuclear Power Plant.

FIGURE 4.1.a.

Levy County Nuclear Power Plant (Levy County)

FIGURE 4.1.b.

Levy County Nuclear Power Plant (Levy County) – Aerial View

Duke Energy Florida
RFP for Power Supply Resources

Notice of Intent to Bid - Non Binding

Name of Bidder / Bidder Contact		
	Bidder Name	____________
	Contact Name	____________
	Address	____________
		____________
	Telephone	____________
	Fax	____________
	E-mail address	____________

Bidder Representatives Attending Bidders Conference		
	Names:	____________
		____________

All potential Bidders are requested to submit an email Notice of Intent to Bid to Duke Energy Florida's Official Contacts by the Bidders Meeting.

E-mail to the Official Contacts:

DEF RFP Contact
DEF2018RFP@duke-energy.com
and
Independent Monitor/Evaluator Contact
Alan.Taylor@sedwayconsulting.com

Schedule A

Project Summary

Name of Bidder		______________	
Bidder Contact	Name	______________	
	Address	______________	
		______________	
		______________	
	Telephone	______________	
	Fax	______________	
	e-mail address	______________	
Project Name		______________	
Project Location	County	______________	
	State	______________	
Contract Start Month/Year		______________	
Term of Proposal	Years	______________	
Seasonal Contract Capacity (MW)	Summer	______________	
	Winter	______________	
Proposal Type	Check One	New Unit	☐
		Existing Unit	☐
		System Power	☐
Generation Technology	Technology	______________	
Fuel Type	Primary	______________	
	Secondary	______________	
Heat Rate @ Max Load	Summer	______________	HHV
	Winter	______________	HHV

Schedule 1[1]
Pricing Schedule for New and Existing Unit Proposals

Contract Start Month
Contract Start Year
Contract End Year

	Contract Year												Contract Year											Contract Year											
Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42	01/01/43	01/01/44	01/01/45	01/01/46	01/01/47	01/01/48	01/01/49	01/01/50	01/01/51	01/01/52
Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42	12/31/43	12/31/44	12/31/45	12/31/46	12/31/47	12/31/48	12/31/49	12/31/50	12/31/51	12/31/52
Seasonal Contract Capacity (MW net)																																			
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																																			
Summer (May, Jun, Jul, Aug, Sep, Oct)																																			
Annual Charges/Prices																																			
Fixed Payment																																			
Generation Capital Charges ($/kW-year)[2]																																			
Fixed O&M Charges ($/kW-year)[2]																																			
Transmission Charges ($/kW-year)[2]																																			
Total Fixed Charges ($/kW-year)																																			
Pipeline Demand/Reservation Charges ($/mmBtu-day)																																			
Variable Payment																																			
Primary Fuel Commodity Price ($/mmBtu)																																			
Primary Fuel Variable Transportation Price ($/mmBtu)																																			
Total Primary Fuel Price ($/mmBtu)																																			
Secondary Fuel Commodity Price ($/mmBtu)																																			
Secondary Fuel Variable Transportation price ($/mmBtu)																																			
Total Secondary Fuel Price ($/mmBtu)																																			
Variable O&M Prices																																			
$/MWh																																			
$/hour																																			
Start Payment																																			
Start Prices ($/Start)																																			

Desired Primary Fuel Price Index ____________________
Desired Secondary Fuel Price Index ____________________

Reference Price Forecasts[3] ($/mmBtu)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Natural Gas, Henry Hub	5.51	5.94	6.70	7.12	7.49	7.74	8.07	8.41	8.76	9.12	9.50	9.89	10.29	10.71	11.14	11.59	12.05	13.23	14.65	15.76	16.68	17.60	18.53	19.45	20.37	21.30	22.22	23.14	24.07	24.99	25.91	26.84	27.76	28.68	29.61
No. 2 Oil, .5% S, delivered to Florida Gulf Coast	18.54	18.66	18.82	19.39	19.97	20.58	21.20	21.85	22.52	23.42	24.25	25.11	26.00	26.71	27.72	28.77	29.86	31.00	32.17	33.39	34.52	35.65	36.79	37.92	39.05	40.19	41.32	42.45	43.59	44.72	45.86	46.99	48.12	49.26	50.39
Coal	3.82	3.93	3.80	3.90	3.99	4.15	4.28	4.42	4.57	4.72	4.87	5.03	5.19	5.35	5.54	5.72	5.91	6.11	6.30	6.50	6.70	6.89	7.09	7.28	7.47	7.67	7.86	8.05	8.25	8.44	8.63	8.83	9.02	9.22	9.41

Notes
1. For instructions on completing this schedule, refer to Response Package, Section II.E.
2. Even though first year will be a partial year, input the ANNUALIZED charges here.
3. Reference Price forecasts are for reference purposes only and may be used to represent an index; they are not firm prices. Forecasts are subject to change.

Schedule 2[1]
Pricing Schedule for System Proposals

Contract Start Month	
Contract Start Year	
Contract End Year	

Contract Year																		
Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35
Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35
Seasonal Contract Capacity (MW net)																		
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																		
Summer (May, Jun, Jul, Aug, Sep, Oct)																		
Annual Charges/Prices																		
Fixed Payment																		
Capacity Charges ($/kW-year)[2]																		
Transmission Charges ($/kW-year)[2]																		
Total Fixed Charges ($/kW-year)																		
Variable Payment																		
System Fuel Energy Price ($/MWh)																		
Non-Fuel Energy Price																		
$/MWh																		
$/hour																		
Start Payment																		
Start Prices ($/Start)																		
[illegible]																		
[illegible]																		
[illegible]																		

Contract Year																	
Number	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Beginning	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42	01/01/43	01/01/44	01/01/45	01/01/46	01/01/47	01/01/48	01/01/49	01/01/50	01/01/51	01/01/52
Ending	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42	12/31/43	12/31/44	12/31/45	12/31/46	12/31/47	12/31/48	12/31/49	12/31/50	12/31/51	12/31/52
Seasonal Contract Capacity (MW net)																	
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																	
Summer (May, Jun, Jul, Aug, Sep, Oct)																	
Annual Charges/Prices																	
Fixed Payment																	
Capacity Charges ($/kW-year)[2]																	
Transmission Charges ($/kW-year)[2]																	
Total Fixed Charges ($/kW-year)																	
Variable Payment																	
System Fuel Energy Price ($/MWh)																	
Non-Fuel Energy Price																	
$/MWh																	
$/hour																	
Start Payment																	
Start Prices ($/Start)																	
[illegible]																	
[illegible]																	
[illegible]																	

Proposed fuel energy price index(es) ____________________

Reference Price Forecasts[3] ($/mmBtu)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Natural Gas, Henry Hub	5.51	5.94	6.70	7.12	7.49	7.74	8.07	8.41	8.76	9.12	9.50	9.89	10.29	10.71	11.14	11.59	12.05	13.23
No. 2 Oil, .5% S. delivered to Florida Gulf Coast	18.54	18.66	18.82	19.39	19.97	20.58	21.20	21.85	22.52	23.42	24.26	25.11	26.00	26.71	27.72	28.77	29.86	31.00
Coal	3.82	3.93	3.80	3.90	3.99	4.15	4.28	4.42	4.57	4.72	4.87	5.03	5.19	5.35	5.54	5.72	5.91	5.11

Reference Price Forecasts[3] ($/mmBtu)	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Natural Gas, Henry Hub	14.65	15.76	16.68	17.60	18.53	19.45	20.37	21.30	22.22	23.14	24.07	24.99	25.91	26.84	27.76	28.68	29.61
No. 2 Oil, .5% S. delivered to Florida Gulf Coast	32.17	33.39	34.52	35.65	36.79	37.92	39.05	40.19	41.32	42.45	43.59	44.72	45.86	46.99	48.12	49.26	50.39
Coal	6.30	6.50	6.70	6.89	7.09	7.28	7.47	7.67	7.86	8.05	8.25	8.44	8.63	8.83	9.02	9.22	9.41

Notes
1. For instructions on completing this schedule, refer to Response Package, Section II.E.
2. Even though first year will be a partial year, input the ANNUALIZED charges here.
3. Reference Price forecasts are for reference purposes only and may be used to represent an index; they are not firm prices. Forecasts are subject to change.

Schedule 3
Capacity States and Heat Rates for New and Existing Unit Proposals[1]

Specify Capacity States (MW)[2] and Net Heat Rates (Btu/kWh)[3] for each Season.
Winter is defined as January, February, March, April, November, and December.
Summer is defined as May, June, July, August, September, and October.

Plant elevation ________ feet

		Contract Year																								
	Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42
	Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42
Required	**Winter Full Load Capacity (MW)**																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Summer Full Load Capacity (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Winter Minimum Load (MW)[4]																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Summer Minimum Load (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
Optional	Winter–Capacity State 2 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Summer–Capacity State 2 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Winter–Capacity State 3 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Summer–Capacity State 3 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Winter–Capacity State 4 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									
	Summer–Capacity State 4 (MW)																									
	Net Heat Rate–Primary Fuel																									
	Net Heat Rate–Secondary Fuel																									

Notes:
1. For instructions on completing this schedule, refer to Response Package, Section II.F.
2. Capacity must be specified at net generation levels at the Delivery Point.
3. All heat rates must be expressed in Btu/kWh, higher heating value (HHV). Heat rates for capacity states must be average, not incremental, heat rates.
Heat rates must incorporate any margin for degradation during the term of the contract. Degradation may be incorporated as an average over the term or annually.
4. The Minimum Load point is considered Capacity State 1.

Schedule 4
Operating Performance Schedule[1]

	Yes	No
Greenfield and Unit Proposals will have a direct communication link with Duke Energy Florida's Control Center that enables Duke Energy Florida to control the operation of the unit under automatic generator control (in DEF's control area) or a combination of dynamic/block scheduling (outside of DEF's control area) **[New Unit Proposal, Existing Unit Proposal]**		
Duke Energy Florida will be able to operate the unit to provide voltage support for the DEF system: **[New Unit Proposal, Existing Unit Proposal] in DEF's control area**		
Duke Energy Florida will be able to operate the unit to provide frequency control for the DEF system: **[New Unit Proposal, Existing Unit Proposal] in DEF's control area**		
The proposed project will be Fully Dispatchable by Duke Energy Florida. **[New Unit Proposal, Existing Unit Proposal]**		
The proposed project will be Fully Schedulable by Duke Energy Florida. **[System Power Proposal]**		
The Bidder agrees to coordinate its maintenance schedule with Duke Energy Florida. **[New Unit Proposal, Existing Unit Proposal]**		
The level of on-site fuel storage (equivalent hours of operation at full load without refilling). **[New Unit Proposal, Existing Unit Proposal]**		

Schedule 4
Operating Performance Schedule[1]
(Continued)

Operating Performance Evaluation Criteria [New Unit Proposal, Existing Unit Proposal]

The maximum capacity level at which each unit may be operated while on AGC _____ MW

The minimum capacity level (MW) at which each unit may be operated _____ MW
The minimum capacity level (MW) while on AGC _____ MW

The guaranteed start time required to bring each unit from a cold start to minimum load would be: _____ minutes

The guaranteed ramp rate for each unit from the minimum loading level: _____ MW/min (facility)
The ramp rate for each unit from the minimum loading level while on AGC _____ MW/min (facility)

The maximum number of starts (per unit) that DEF would be allowed per year: _____ starts/year (unit)
(Test starts and starts after a forced outage or unscheduled maintenance will not be included when determining the number of starts requested by DEF.)

The minimum run time when each unit has been dispatched on line would be: _____ hours

The minimum down time when each unit has been taken off-line would be: _____ hours

The maximum number of hours during a year that DEF would be allowed to operate the facility (air permit limit): _____ hours (facility)

Outage Information [New Unit Proposal, Existing Unit Proposal]

The Equivalent Forced Outage Rate Guarantee is _________

Specify the average number of days per year of scheduled maintenance for each unit, consistent with Schedule 3.

Unit	Maintenance days per year

Notes:
[1] For instructions on completing this schedule, refer to Response Package, Section II.F.

Schedule 5
Environmental and Regulatory Permit Status Schedule

Item	Not Required	Required	Applied For (Date)	Expected Receipt (Date)
Water Discharge to Surface Waters (NPDES) Permit				
404 Permit / 401 Water Quality Certification				
Domestic Wastewater				
Industrial Wastewater (non-NPDES)				
Water Use				
Water Use Area Restrictions (e.g. SWUCA, MIA) Applicability				
Corps of Engineers Permit(s): wetlands / aerial crossings				
Environmental Resource Permit (ERP) for Wetlands				
ERP: Surface Water Management (MSSW)				
Solid Waste Disposal Permit				
Ash Disposal Permit				
Hazardous Waste Disposal Permit				
PSD (Air Construction) Permit				
Federal Aviation Administration License				
Certificate of Need				
Local Construction Permit				
Local Zoning Approval (Conditional Use Permit)				
Spill Prevention Control Measures Permit				
Section 10 (Wildlife) Permits				
Migratory Bird				
Department of Transportation				
Air: Title V Operating Permit				
Electric and Magnetic Field (EMF) requirements: FDEP				
Title IV (Acid Rain) Permit				
Site Certification Application (includes state, local permitting and authorizations) or Supplemental SCA if existing site				

Schedule 6
Air Emissions Schedule

Primary Fuel						
Fuel Type:	0		Maximum Hours of Operation:			
Pollutant	Facility at Maximum Load Conditions				Facility Total (Including all sources at ISO conditions)	
	ppm	lbs/MMBtu	lbs/hr	Tons/yr	lbs/hr	Tons/yr
NOx						
VOCs						
SO2						
CO						
PM						
Sulfuric Acid Mist						
Hazardous Air						

Secondary Fuel						
Fuel Type:	0		Maximum Hours of Operation:			
Pollutant	Facility at Maximum Load Conditions				Facility Total (Including all sources at ISO conditions)	
	ppm	lbs/MMBtu	lbs/hr	Tons/yr	lbs/hr	Tons/yr
NOx						
VOCs						
SO2						
CO						
PM						
Sulfuric Acid Mist						
Hazardous Air						

Maximum Hours of Operation: ______ hours
(sum of all fuels; consistent with Schedule 4, page 2)

Schedule 7
Transmission Information Schedule

Check the appropriate box and provide the requested information:

☐ **New Unit Proposal (Unit Inside DEF)**

1 Interconnection Request Queue Position and Date ______________________
2 Submit all information requested in the Interconnection Request for a Large Generating Facility (see Appendix 1 of Attachment J (LGIP) in DEF's OATT), which can be found at http://www.ferc.duke-energy.com/Joint_OATT.pdf.
3 Customer to confirm agreement that the Large Generator scoping meeting will be delayed until such time that DEF determines the LGIA interconnection studies should move forward. Refer to attachment J section 3.3.4 in the DEF OATT.
4 Non binding good faith estimate of the directly assignable interconnection facilities costs associated with the proposed interconnecion

☐ **New Unit Proposal (Unit Outside DEF)**

1 Host/Source system ______________________
2 Submit a completed transmission interconnection feasibility study report or a transmission service agreement study report from the host utility.
3 Submit all information requested in the Interconnection Request for a Large Generating Facility as submitted to the Host system (see Appexdix 1 of Attachment J (LGIP) in DEF's OATT), which can be found at http://www.ferc.duke-energy.com/Joint_OATT.pdf.
4 Non binding good faith estimate of the directly assignable interconnection facilities costs associated with the proposed interconnecion

☐ **Existing Unit Proposals (Unit Inside DEF)**

1 Nothing required for the generator queue process since the unit is already interconnected to the DEF system.

☐ **Existing Unit Proposals (Unit Outside DEF)**

1 Host/Source System ______________________
2 Submit a completed transmission system impact study agreement from the host system or a confirmed point to point transmission reservation from the host system.

☐ **System Power Proposal (Outside DEF)**

1 Host/Source system ______________________
Submit a completed transmission system impact study agreement from the host system or a confirmed point to point transmission reservation from the host system. ______________________

Contact information for transmission planner from the host system utility:
[New and Existing Unit Proposals Outside DEF, System Power Proposals]

Company: ______________________
Name: ______________________
Street Address: ______________________
P.O. Box: ______________________
City, State, Zip Code: ______________________
Phone Number: ______________________
Fax: ______________________
Email: ______________________

Schedule 8
Project Pro Forma Schedule[1]
($ 000's)

Schedule 8
Project Pro Formas Schedule[1]
($ 000's)

PROJECT ASSUMPTIONS

Total Project Capital Cost ($ 000's) →	
Debt Ratio (%) →	
Debt Cost (%) →	
Debt Term (yrs) →	

Line No.		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	Operating Revenues															
1	Capacity Payments →															
2	Fixed O&M Payments →															
3	Energy Payments →															
4	Other Revenues (explain) →															
5	Total Revenues (1+2+3+4)	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0
	Operating Expenses															
6	Fuel - Commodity Costs →															
7	Fuel - Transportation Costs →															
8	Variable Operation & Maintenance Costs →															
9	Fixed Operation & Maintenance Costs →															
10	Wheeling Charges →															
11	Insurance →															
12	Property Taxes →															
13	Administration →															
14	Other Expenses (identify) →															
15	Total Operating Expenses (6+7+8+9+10+11+12+13+14)	[illegible]	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Net Operating Income - Before Tax (5-15)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Income Taxes															
17	Tax Depreciation and Amortization →															
18	Interest Expense →															
19	Other Income / (Deductions) - Net →															
20	Taxable Income (16-17-18+19)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	State Income Taxes Payable →															
22	Federal Income Taxes Payable →															
23	Income Taxes Payable (21+22)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0
	After-Tax Cash Flow															
24	Principal Payments →															
25	Reserve Deposits / (Withdrawals) - Net →															
26	Net After Tax Cash Flow (16-18+19-23-24-25)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Debt Service Coverage Ratio (16)/(18+24)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Line No.		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
	Operating Revenues															
1	Capacity Payments →															
2	Fixed O&M Payments →															
3	Energy Payments →															
4	Other Revenues (explain) →															
5	Total Revenues (1+2+3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Operating Expenses															
6	Fuel - Commodity Costs →															
7	Fuel - Transportation Costs →															
8	Variable Operation & Maintenance Costs →															
9	Fixed Operation & Maintenance Costs →															
10	Wheeling Charges →															
11	Insurance →															
12	Property Taxes →															
13	Administration →															
14	Other Expenses (identify) →															
15	Total Operating Expenses (6+7+8+9+10+11+12+13+14)	0	[illegible]	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	Net Operating Income - Before Tax (5-15)	0	0	0	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Income Taxes															
17	Tax Depreciation and Amortization →															
18	Interest Expense →															
19	Other Income / (Deductions) - Net →															
20	Taxable Income (16-17-18+19)	0	0	0	0	0	0	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21	State Income Taxes Payable →															
22	Federal Income Taxes Payable →															
23	Income Taxes Payable (21+22)	0	0	0	0	0	0	0	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]
	After-Tax Cash Flow															
24	Principal Payments →															
25	Reserve Deposits / (Withdrawals) - Net →															
26	Net After Tax Cash Flow (16-18+19-23-24-25)	0	0	0	0	0	0	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Debt Service Coverage Ratio (16)/(18+24)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Line No.		2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
	Operating Revenues															
1	Capacity Payments →															
2	Fixed O&M Payments →															
3	Energy Payments →															
4	Other Revenues (explain) →															
5	Total Revenues (1+2+3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Operating Expenses															
6	Fuel - Commodity Costs →															
7	Fuel - Transportation Costs →															
8	Variable Operation & Maintenance Costs →															
9	Fixed Operation & Maintenance Costs →															
10	Wheeling Charges →															
11	Insurance →															
12	Property Taxes →															
13	Administration →															
14	Other Expenses (identify) →															
15	Total Operating Expenses (6+7+8+9+10+11+12+13+14)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0
16	Net Operating Income - Before Tax (5-15)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Income Taxes															
17	Tax Depreciation and Amortization →															
18	Interest Expense →															
19	Other Income / (Deductions) - Net →															
20	Taxable Income (16-17-18+19)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21	State Income Taxes Payable →															
22	Federal Income Taxes Payable →															
23	Income Taxes Payable (21+22)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0
	After-Tax Cash Flow															
24	Principal Payments →															
25	Reserve Deposits / (Withdrawals) - Net →															
26	Net After Tax Cash Flow (16-18+19-23-24-25)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0
27	Debt Service Coverage Ratio (16)/(18+24)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes
[1] Bidders should enter data by each line item marked with an arrow. Shaded cells will be automatically calculated by the spreadshee

Notes
[1] Bidders should enter data by each line item marked with an arrow. Shaded cells will be automatically calculated by the spreadsheet.

Schedule 9
Project Milestone Schedule

For all items other than Commercial Operation Date, specify the number of months prior to Scheduled Commercial Operation Date

Site Acquisition:	
Fuel Supply Contract:	
Facility Contracts:	
Public Service Commission Approval:	
Air Permit:	
Commencement of Construction:	
Delivery of Turbine-Generator Equipment:	
Wheeling Agreements:	
Financial Closing:	
Commercial Operation Date:	

The Bidders meeting is scheduled for October 18 at the Marriott Tampa Westshore, 1001 N Westshore Blvd, Tampa, Florida 33607 (1:00 – 3:00pm Westshore Room).

Bidders Meeting

Join the meeting

AUDIO INFORMATION

Telephone Conferencing

Choose one of the following:

- Dial the conferencing service directly, and enter the participant code shown below:
  Toll-free: +1-8887465325
  Participant Code: 3997449

Schedule

A schedule for critical dates for the solicitation, evaluation, screening of proposals, and subsequent negotiations follow:

A. Solicitation	
Pre-Release of RFP	9/24/2013
Pre-Release Meeting	10/2/2013
Issuance of RFP	**10/8/2013**
Bidders Meeting	10/18/2013
Submission of Proposals	**12/9/2013 by 3:00 pm**
B. Evaluation and Screening of Proposals	
Selection of Short List	Expected by 3/2014
Selection of Finalist(s)	**Expected by 5/2014**
C. Negotiations	
Initiate Negotiations	Expected by 5/2014
Clarifications and Adjustments	Expected by 6/2014
Award Announcement	Expected by 8/2014
D. Regulatory Filings	
File for certification	Expected by 9/2014

DEF reserves the right to revise the schedule at any time, at DEF's sole discretion. Depending on DEF's requirements to review the proposals, DEF may shorten or lengthen the schedule and revise the dates associated with the schedule.

Duke Energy Florida
RFP for Power Supply Resources

Notice of Intent to Bid - Non Binding

Name of Bidder	Bidder Name	______________________
	Contact Name	______________________
Bidder Contact	Address	______________________
		______________________
	Telephone	______________________
	Fax	______________________
	E-mail address	______________________
Bidder Representatives Attending Bidders Conference	Names:	______________________
		______________________

All potential Bidders are requested to submit an email Notice of Intent to Bid to Duke Energy Florida's Official Contacts by the Bidders Meeting.

E-mail to the Official Contacts:

DEF RFP Contact
DEF2018RFP@duke-energy.com
and
Independent Monitor/Evaluator Contact
Alan.Taylor@sedwayconsulting.com

APPENDIX B

Program Description and Progress

Program Title: Home Energy Check

Program Description: The Home Energy Check program is a comprehensive residential energy evaluation (audit) program. The program provides Duke Energy Florida, Inc.'s (DEF) residential customers with an analysis of energy consumption and recommendations on energy efficiency improvements. It acts as a motivational tool to identify, evaluate, and inform consumers on cost effective energy saving measures. It serves as the foundation of the residential Home Energy Improvement program and is a program requirement for participation. There are seven types of the energy audit: the free walk-thru, the paid walk-thru ($15 charge), the energy rating (Energy Gauge), the mail-in audit, an internet option, a phone assisted audit, and a student audit.

Program Accomplishments for January 2013 through December 2013:
31,643 customers participated in Home Energy Checks.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $7,631,853.

Program Progress Summary: To-date 778,295 customers have participated in Home Energy Check. Duke Energy Florida will continue to use the Home Energy Check to inform and motivate consumers to implement cost effective energy efficiency measures and qualify for Home Energy Improvement incentives.

APPENDIX B

Program Description and Progress

Program Title: Home Energy Improvement

Program Description: Home Energy Improvement is an umbrella program for residential customers with existing homes. This program combines thermal envelope efficiency improvements with upgraded equipment and appliances. The Home Energy Improvement program includes incentives for measures such as duct testing, duct leakage repair, attic insulation, injected wall insulation, replacement windows, window film, reflective roofing, high efficiency heat pump replacing resistance heat, high efficiency heat pump replacing a heat pump, high efficiency A/C replacing A/C with non-electric heat, HVAC commissioning, plenum sealing, proper sizing and supplemental bonuses.

Program Accomplishments for January 2013 through December 2013: There were 29,724 measures implemented under this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $6,138,247.

Program Progress Summary: To-date 573,246 Home Energy Improvement measures have been implemented. This program will continue to be offered to residential customers through the Home Energy Check to provide opportunities for improving the energy efficiency of existing homes.

APPENDIX B

Program Description and Progress

Program Title: Residential New Construction

Program Description: The Home Advantage Program promotes energy-efficient construction which exceeds the building code. Information, education, and consultation are provided to homebuilders, contractors, realtors and home buyers on energy-related issues and efficiency measures. This program is designed to encourage single, multi, and manufactured home builders to build more energy efficiently by encouraging a whole house performance view including the installation of climate effective windows, reflective roof materials, upgraded insulation, conditioned space air handler placement, energy recovery ventilation, and highly efficient HVAC equipment. Incentives are awarded to the builder based on the level of efficiency they choose.

Program Accomplishments for January 2013 through December 2013: There were 23,469 measures implemented through this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $3,863,861.

Program Progress Summary: To-date 264,788 measures have been implemented through the Residential New Construction program. This program is tied to the building industry's economic health and these forces will dictate the number of homes built during any given year.

APPENDIX B

Program Description and Progress

Program Title: Neighborhood Energy Saver

Program Description: The Neighborhood Energy Saver Program was designed to assist low-income families with managing energy costs. The goal of this program is to implement a comprehensive package of electric conservation measures at no cost to eligible customers. Additionally, Duke Energy Florida will endeavor to educate the participating families to better manage their energy usage through efficiency techniques and practices.

Program Accomplishments for January, 2013 through December, 2013: There were 2,911 customers who participated in the Neighborhood Energy Saver program.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $1,283,067.

Program Progress Summary: To-date 17,833 customers have benefited from the Neighborhood Energy Saver Program. This program will continue to be offered to low-income neighborhoods in Duke Energy Florida's service territories.

APPENDIX B

Program Description and Progress

Program Title: Low-Income Weatherization Assistance Program (LIWAP)

Program Description: The program goal is to integrate DEF's DSM program measures with the Department of Economic Opportunity (DEO) and local weatherization providers to deliver energy efficiency measures to low-income families. Through this partnership Duke Energy Florida will assist local weatherization agencies by providing energy education materials and financial incentives to weatherize the homes of low-income families.

Program Accomplishments for January 2013 through December 2013: There were 1,750 measures implemented in the program in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $224,641.

Program Progress Summary: To-date 18,659 measures have been implemented through the Low-Income Weatherization Assistance Program (LIWAP). Duke Energy Florida participates in local, state-wide and national agency meetings to promote the delivery of LIWAP programs. Individual meetings with weatherization providers and other low income providers are conducted throughout DEF's territory to encourage customer participation in energy efficiency programs.

APPENDIX B

Program Description and Progress

Program Title: Energy Management (Residential & Commercial)

Program Description: The Load Management Program is a voluntary program that incorporates direct radio control of selected customer equipment to reduce system demand during winter and summer peak capacity periods and/or emergency conditions by temporarily interrupting selected customer appliances for specified periods of time. Customers have a choice of options and receive a credit on their monthly electric bills depending on the options selected and their monthly kWh usage.

Program Accomplishments for January 2013 through December 2013: During this period 4,321 customers were added to the residential program. The commercial program was closed to new participants in April 2001.

Program Fiscal Cost for January 2013 through December 2013: Residential program expenditures during this period were $50,369,626 and commercial expenditures were $596,873.

Program Progress Summary: As of December 31, 2013 there were 394,387 residential customers and 359 commercial customers participating in the Load Management program.

APPENDIX B

Program Description and Progress

Program Title: Business Energy Check

Program Description: The Business Energy Check is an audit for non-residential customers, and several options are available. The free audit provides a no-cost energy audit for non-residential facilities and can be completed at the facility by an auditor or online by the business customer. The paid audit provides a more thorough energy analysis for non-residential facilities. This program acts as a motivational tool to identify, evaluate, and inform consumers on cost effective energy saving measures for their facility. It serves as the foundation of, and is a requirement for participation in, the Better Business Program.

Program Accomplishments for January 2013 through December 2013: There were 2,070 customers who participated in this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $2,298,401.

Program Progress Summary: To-date 36,942 non-residential customers have participated in the Business Energy Check. This program will continue to inform and motivate consumers on cost effective energy efficiency improvements which result in implementation of energy efficiency measures. The program is required for participation in most of the company's other DSM Business incentive programs.

APPENDIX B

Program Description and Progress

Program Title: Better Business

Program Description: This umbrella efficiency program provides incentives to existing commercial and industrial customers for heating, air conditioning, motors, roof insulation upgrade, duct leakage and repair, window film, demand-control ventilation, lighting, occupancy sensors, green roof, cool roof, high efficiency energy recovery ventilation, compressed air, and HVAC optimization.

Program Accomplishments for January 2013 through December 2013: There were 992 measures implemented under this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $1,857,858.

Program Progress Summary: To-date 15,560 measures have been implemented through the Better Business Program. This program will continue to be offered to commercial customers through the Business Energy Check to provide opportunities for improving the energy efficiency of existing facilities.

APPENDIX B

Program Description and Progress

Program Title: Commercial/Industrial New Construction

Program Description: This is an umbrella efficiency program for new Commercial and Industrial facilities. This program provides information, education, and advice on energy-related issues and efficiency measures by involvement early in the building's design process. With the exception of ceiling insulation upgrade, duct test and leakage repair, HVAC steam cleaning and roof top HVAC unit recommissioning, the Commercial and Industrial New Construction program provides incentives for the same efficiency measures listed in the Better Business program for existing buildings.

Program Accomplishments for January 2013 through December 2013: There were 246 measures implemented in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $1,112,112.

Program Progress Summary: To-date 1,735 measures have been implemented through the Commercial/Industrial New Construction program. This program is tied to the building industries economic health and these forces will dictate the number of commercial facilities built during any given period.

APPENDIX B

Program Description and Progress

Program Title: Innovation Incentive

Program Description: Significant conservation efforts that are not supported by other Duke Energy Florida programs can be encouraged through Innovation Incentive. Major equipment replacement or other actions that substantially reduce DEF peak demand requirements are evaluated to determine their impact on Duke Energy Florida's system. Incentives are provided for customer-specific demand and energy conservation projects on a case-by-case basis, where cost-effective to all DEF customers. To be eligible, projects must reduce or shift a minimum of 10 kW of peak demand.

Program Accomplishments for January 2013 through December 2013: There were a total of 13 projects completed that qualified for incentives in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $64,858.

Program Progress Summary: To-date 190 projects have completed incentives through the Innovation Incentive program. This program continues to target specialized, customer specific energy efficiency measures not covered through the company's other DSM programs.

APPENDIX B

Program Description and Progress

Program Title: Standby Generation

Program Description: Duke Energy Florida provides an opportunity for commercial customers to voluntarily operate their on-site generators during times of system peak. Participants receive an incentive per kW available, as well as a kWh supplement for runtime during times of system peak.

Program Accomplishments for January 2013 through December 2013: There were 12 new accounts added to the program during this period.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $4,587,513.

Program Progress Summary: A total of 256 accounts are currently participating in this program.

APPENDIX B

Program Description and Progress

Program Title: Interruptible Service Program

Program Description: The Interruptible Service program is a rate tariff which allows Duke Energy Florida to switch off electrical service to customers during times of capacity shortages. The signal to operate the automatic switch on the customer's service is activated by the Energy Control Center. In return for this, the customers receive a monthly rebate on their kW demand charge.

Program Accomplishments for January 2013 through December 2013: There were 4 new participant added to the program under the IS-2 tariff during this period.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $24,703,515.

Program Progress Summary: The program currently has 134 active accounts with 105 IS-1 accounts, 23 IS-2 accounts, 4 SS-2 accounts, and two SECI-IS accounts. The original program filed as the IS-1 tariff is no longer cost-effective under the Commission approved test and was closed on April 16, 1996. Existing participants were grandfathered into the program. New participants are placed on the IS-2 tariff.

APPENDIX B

Program Description and Progress

Program Title: Curtailable Service Program

Program Description: The Curtailable Service is a dispatchable DSM program in which customers contract to curtail or shut down a portion of their load during times of capacity shortages. The curtailment is done voluntarily by the customer when notified by DEF. In return for this cooperation, the customer receives a monthly rebate for the curtailable portion of their load.

Program Accomplishments for January 2013 through December 2013: There were no new participants added to this program in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $878,351.

Program Progress Summary: The program currently has 4 accounts with 3 CST-1 accounts and 1 SS-3 accounts. The original program filed as the CS-1 tariff is no longer cost-effective under the Commission approved test and was closed on April 16, 1996. Existing participants were grandfathered into the program. New participants are placed on the CS-2 tariff.

APPENDIX B

Program Description and Progress

Program Title: Solar Water Heating with Energy Management Program

Program Description: This program is part of DEF's Demand-Side Renewable Portfolio and encourages residential customers to install a solar thermal water heating system. Customers are required to complete a Home Energy Check before the solar thermal system is installed. To receive the one-time $550 incentive, the heating, air conditioning, and water heating systems must be on the Energy Management program and the solar thermal system must provide a minimum of 50% of the water heating load.

Program Accomplishments for January, 2013 through December, 2013: There were 259 customers that participated in the Solar Water Heater with Energy Wise.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $170,584.

Program Progress Summary: This program was implemented in 2011, along with a new online application process and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Solar Water Heating Low Income Residential Pilot

Program Description: The Solar Water Heating Low Income Residential Customers Pilot is part of DEF's Demand-Side Renewable Portfolio and designed to assist low income families with managing energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. Duke Energy Florida will collaborate with non-profit builders to provide low income families with a residential solar thermal water heater. The solar thermal system will be provided at no cost to the non-profit builders or the residential participants.

Program Accomplishments for January, 2013 through December, 2013: There were 24 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $123,594.

Program Progress Summary: This pilot program was implemented in 2011 and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Residential Solar Photovoltaic Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and encourages residential customers to install new solar photovoltaic (PV) systems on their home. Customers are required to complete a Home Energy Check before the PV system is installed. The pilot program includes an annual reservation process for pre-approval to ensure the maximum incentive funds are available for participation. Participants can receive a rebate up to $2.00 per Watt of the PV dc power rating up to a $20,000 maximum for installing a new PV system.

Program Accomplishments for January, 2013 through December, 2013: There were 152 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $2,445,475.

Program Progress Summary: This pilot program was implemented in 2011, along with an online application process. Duke Energy Florida will continue to offer this program in its service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Commercial Solar Photovoltaic Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and encourages commercial customers to install new solar photovoltaic (PV) systems on their facilities. Additionally, the pilot program promotes the installation of renewable energy on energy efficient businesses by requiring customers to complete a Business Energy Check prior to installation. The program design includes an annual reservation process for pre-approval to ensure the maximum incentive funds are available for participation. Participants can receive a rebate up to $2.00 per Watt of the PV DC power rating for the first 10 KW, $1.50 per Watt for 11KW to 50 KW, and $1.00 per Watt for 51 KW to 100 KW, up to a $130,000 maximum for installing a new PV system.

Program Accomplishments for January, 2013 through December, 2013: There were 12 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $920,291.

Program Progress Summary: This pilot program was implemented in 2011, along with an online application process, and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Photovoltaic for Schools Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and is designed to promote energy education and provide participating public schools with new solar photovoltaic (PV) systems at no cost to the school. The pilot program will be limited to an annual target of one system with a rating up to 100 kW installed on a post secondary school and up to ten (10) 10 kW systems with battery backup option installed on schools, preferably those serving as emergency shelters.

Program Accomplishments for January, 2013 through December, 2013: There were 11 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $1,054,297.

Program Progress Summary: This pilot program was implemented in 2011 and will continue to be offered in Duke Energy Florida's service territories through 2014. Photovoltaic systems were started at ten primary and one post secondary public school. The post secondary school was completed in 2013 the remaining primary schools will be completed in 2014.

APPENDIX B

Program Description and Progress

Program Title: Research and Demonstration Pilot

Program Description: The purpose of this program component is to research technology and establish R&D 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 focus of this pilot is to establish associated impacts from increased solar PV penetration in order to enhance the program cost benefit study and incorporate mitigation, as necessary, within the program eligibility standards. Additional objectives include enhanced understanding on the performance variability from different solar PV technologies, and research on economic impact and funding mechanisms.

The program will be limited to a targeted annual expenditure cap of 5% of the total Demand-Side Renewable Portfolio annual expenditures.

Program Accomplishments for January, 2013 through December, 2013: Several research and development projects continued and/or launched in 2013.

- Enhanced and continued data collection to document solar resource on distribution feeders associated with our solar PV monitoring project
- Established a study to determine impacts from increased penetration of PV resources on distribution circuits utilizing data collected in our PV monitoring project
- Partnered with EPRI to evaluate Flat Plate PV arrays
- Participated in EPRI programs 84 and 174; Renewables, Economics, and Technology Status; and Integrating Renewables into Distribution

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $11,026.

Program Progress Summary: The Research and Demonstration Pilot was initiated during 2011 along with the Demand Side Renewable Portfolio of pilot programs. This research pilot will continue through 2014.

APPENDIX B

Program Description and Progress

Program Title: Technology Development

Program Description: This program allows Duke Energy Florida, Inc. to undertake certain development and demonstration projects which have promise to become cost-effective conservation and energy efficiency programs.

Program Accomplishments for January 2013 through December 2013:
Several research and development projects continued and/or launched in 2013.

- Continued battery storage technology analysis by evaluating two Li-Ion batteries associated with the Renewable SEEDS project; final report to be completed in 2013
- Data collection and evaluation of Variable Speed HPs with the potential of eliminating strip heat as a back-up heat source for heat pumps
- Participated in EPRI Program 94 and 18D, Energy Storage and Electric Transportation Systems Infrastructure and Utility Readiness
- Partnered with EPRI and other research organizations to evaluate energy efficiency, energy storage, and alternative energy / innovative technologies

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $251,317.

Program Progress Summary:
In 2013, Duke Energy Florida continued to focus on advancing new technologies which have the potential to provide new programs and create new customer offerings that continue to focus on using energy responsibly. We will continue to study several technologies such as energy storage, energy efficiency, and control automation so that we can fully understand the impacts these will have to our grid and our customer programs. Accomplishments in 2013 included: evaluating and collecting the data from the heat pump energy efficiency product that will eliminate the need for strip heat, working with EPRI and other utilities to advance EVSE for demand response capabilities, and working with EPRI to study energy storage cost benefit analysis. All of this research is tied to our strategic objectives to provide customers cost effective conservation and energy efficiency programs.

APPENDIX B

Program Description and Progress

Program Title: Qualifying Facility

Program Description: Power is purchased from qualifying cogeneration, renewables and small power production facilities.

Program Accomplishments for January, 2013 through December, 2013: Duke Energy Florida met with many Qualified Facility developers interested in providing renewable generation within our service territory. On-going discussions with renewable and CHP developers continue to progress with market changes, an increase in interest in project development, as well as technology advances. As the number of potential developers grow, more in depth policy and analytics are required to support these purchased power negotiations. Discussions have been held with current Qualified Facilities to extend soon to expire purchase agreements. The contracts under development are being diligently monitored for construction milestones, financing status, permitting, transmission studies and agreements, insurance and Performance Security. Duke Energy Florida continues to successfully administer all executed contracts with Qualified Facilities for compliance. These contracts produced more than 3.98 Million MWHs for Duke Energy Florida customers during 2013. That's equal to the average annual electricity use of about 370,000 average households.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $858,618.

Program Progress Summary:
As of December 31, 2013, the total firm capacity from in-service Qualifying Facilities is approximately 529 MW with an additional 150 MW of firm capacity and 300 MW of As-Available energy contracts are being monitored for future service.

APPENDIX C

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for approval of demand-side management plan of Progress Energy Florida, Inc.	DOCKET NO. 100160-EG ORDER NO. PSC-11-0347-PAA-EG ISSUED: August 16, 2011

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
JULIE I. BROWN

NOTICE OF PROPOSED AGENCY ACTION
ORDER MODIFYING AND APPROVING DEMAND-SIDE MANAGEMENT PLAN

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Case Background

As required by the Florida Energy Efficiency and Conservation Act (FEECA), Sections 366.80 through 366.85 and 403.519, Florida Statutes (F.S.), we have adopted annual goals for seasonal peak demand and annual energy consumption for the FEECA Utilities. These include Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), JEA, and Orlando Utilities Commission (OUC).

Pursuant to Rule 25-17.008, Florida Administrative Code (F.A.C.), in any conservation goal setting proceeding, we require each FEECA utility to submit cost-effectiveness information based on, at a minimum, three tests: (1) the Participants test; (2) the Rate Impact Measure (RIM) test, and (3) the Total Resource Cost (TRC) test. The Participants test measures program cost-effectiveness to the participating customer. The RIM test measures program cost-effectiveness to the utility's overall rate payers, taking into consideration the cost of incentives paid to participating customers and lost revenues due to reduced energy sales that may result in the need for a future rate case. The TRC test measures total net savings on a utility system-wide basis. In past goal setting proceedings, we established conservation goals based primarily on measures that pass both the Participants test and the RIM test.

The 2008 Legislative Session resulted in several changes to the FEECA Statutes, and our 2008 goal-setting proceeding was the first implementation of these modifications. By Order No. PSC-09-0855-FOF-EG, issued December 30, 2009, in Docket Number 080408-EG, we established annual numeric goals for summer peak demand, winter peak demand, and annual energy conservation for the period 2010 through 2019, based upon an unconstrained Enhanced-Total Resource test (E-TRC) for the investor-owned utilities (IOUs). The E-TRC test differs from the conventional TRC test by taking into consideration an estimate of additional costs imposed by the potential regulation of greenhouse gas emissions. In addition, the numeric impacts of certain measures with a payback period of two years or less were also included in the goals. Further, the IOUs subject to FEECA were authorized to spend up to 10 percent of their historic expenditures through the Energy Conservation Cost Recovery (ECCR) clause as an annual cap for pilot programs to promote solar water heating (Thermal) and solar photovoltaic (PV) installations.

On January 12, 2010, PEF filed a Motion for Reconsideration of our goal setting decision in Docket No. 080408-EG. Order No. PSC-10-0198-FOF-EG, issued March 31, 2010, granted, in part, PEF's reconsideration which revised PEF's numeric goals to correct a discovery response that caused a double-counting error. On March 30, 2010, PEF filed a petition requesting approval of its Demand-Side Management (DSM) Plan pursuant to Rule 25-17.0021, Florida Administrative Code (F.A.C.) (Docket No. 100160-EG). The Florida Industrial Users Group (FIPUG), White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate), the Southern Alliance for Clean Energy (SACE), the Florida Solar Energy Industry Association (FlaSEIA), and Wal-Mart Stores East, LP, and Sam's East, Inc. (Walmart) were all granted leave to intervene in the proceeding.

On July 14, 2010, SACE filed comments on the FEECA Utilities' DSM Plans. These comments were amended on August 3, 2010, to include comments regarding FPUC. No other intervenors filed comments. On July 28, and August 12, 2010, PEF and Gulf, respectively, filed responses to SACE's comments.

On September 1, 2010, our staff filed a recommendation, noting that the DSM Plan filed by PEF on March 30, 2010, did not meet all annual goals we set for PEF in Order No. PSC-10-0198-FOF-EG. On October 4, 2010, we issued Order No. PSC-10-0605-PAA-EG approving six solar pilot programs but denying the remainder of PEF's petition and directing the Company to modify its DSM Plan to meet the annual goals we originally set. During the discussion at the September 14, 2010, Commission Conference, we also encouraged PEF to provide an alternative DSM Plan to reduce the customer rate impact in addition to the DSM Plan to meet our original goals. Therefore, on November 29, 2010, the Company filed two DSM Plans: an Original Goal Scenario DSM Plan and a Revised Goal DSM Plan. For clarity and ease of reference, the Original Goal Scenario DSM Plan, which features programs designed to meet the full demand and energy savings goals, will be referred to throughout the remainder of this Order as the "Compliance Plan" and the Revised Goal DSM Plan, which has a lower rate impact, but reduced projected savings, will be referred to as the "Rate Mitigation Plan."

On December 22, 2010, SACE filed a letter offering comments on the DSM plans submitted by PEF and several of the other IOUs. The letter references the August 3, 2010, filing by SACE relating to the PEF's initial DSM filing, and updates several issues relating to the Company's new DSM Plans. On April 25, 2011, SACE filed another letter offering similar comments and recommendations with regard to PEF's new DSM Plans filed on November 29, 2010, and FPL's modified and alternate DSM Plans filed March 25, 2011. On May 9, 2011, SACE filed a letter providing its comparison of PEF's proposed DSM plans filed on November 29, 2010, with Progress Energy Carolina's DSM/energy efficiency cost recovery rider application filed on May 2, 2011, with the South Carolina Public Service Commission. We have jurisdiction over this matter pursuant to Sections 366.80 through 366.85, F.S.

PEF's Compliance Plan

As noted above, PEF's initial filing submitted March 30, 2010, was insufficient to meet several of the annual goals in multiple categories. We directed PEF, in Order No. PSC-10-0605-PAA-EG, to file a modified DSM Plan which would comply with the goal-setting Order. However, the Compliance Plan PEF filed on November 29, 2010, still failed to fully meet the goals we established. Specifically, PEF's filing failed to achieve the annual and cumulative summer and winter demand (MW) goals for the commercial sector. Consequently, our staff sent a data request[1] to PEF requesting an explanation for PEF's failure to comply with our Order. PEF responded that it had inadvertently developed the portfolio of commercial programs in the Compliance Plan based upon an estimate of the commercial summer and winter demand (MW) goals "at-the-meter" rather than targeting the actual Commission-established demand goals which are "at-the-generator." This resulted in the assumed commercial demand savings being less than the established demand goals. PEF modified anticipated participation levels for measures within its Better Business program which were sufficient to eliminate the deficiency. With the provision of these modifications, PEF's Compliance Plan satisfies our Order and features programs designed to fully meet the established demand and energy savings goals.

Compliance Plan Programs

PEF's Compliance Plan includes seven residential programs and ten commercial/industrial programs. One of the residential programs, Technical Potential, is new. Three of the commercial/industrial programs are new: Commercial Green Building, Business Energy Saver, and Business Energy Response. Modifications, such as adding new measures, have been made to most of the programs. The status of each program relative to PEF programs currently in effect is indicated in Table 1, below.

[1] Staff's 10th Data Request to PEF, Question Number 1 (a – d), issued December 9, 2010.

Table 1 – Compliance Plan Programs

Program Name	Program Status
Residential Portfolio	
1. Technical Potential	New
2. Home Energy Improvement	Modified
3. Residential New Construction	Modified
4. Neighborhood Energy Saver	Modified
5. Low Income Weatherization Assistance	Modified
6. Home Energy Check	Modified
7. Residential Energy Management	Existing
Commercial/Industrial Portfolio	
1. Business Energy Check	Modified
2. Commercial Green Building	New
3. Business Energy Saver	New
4. Commercial/Industrial New Construction	Modified
5. Better Business	Modified
6. Innovation Incentive	Modified
7. Business Energy Response	New
8. Interruptible Service	Modified
9. Curtailable Service	Modified
10. Standby Generation	Modified
Renewable Portfolio	
1. Qualifying Facilities	Existing
2. Technology Development	Modified

Rate Impact of Compliance Plan

The costs to implement a DSM program consist of administrative expenses, equipment costs, and incentive payments to the participants, all of which are recovered by the Company through its ECCR clause. This clause represents a monthly bill impact to customers as part of the non-fuel cost of energy on their bills. Utility incentive payments, not included in the E-TRC, are recovered through the utility's ECCR factor and have an immediate impact on customer rates.

Much like investments in generation, transmission, and distribution, investments in energy efficiency have an immediate rate impact but produce savings over time. Table 2 shows the ECCR Expenditures and Rate Impact on a typical residential customer's bill under the Compliance Plan over ten years. The monthly bill impact of PEF's ECCR factor would range from $11.28 in 2011 to $16.52 in 2014, when we are due to revisit the conservation goals as required by Section 366.82(6), F.S.

Table 2 - Estimated Rate Impact of PEF's Compliance Plan Associated with Goals (1,200 kWh Residential Bill)

Year	ECCR Component ($/mo)	Estimated Residential Bill ($/mo)	Percent of Bill (% Bill)
2010	$3.24	$154.58	2.10%
2011	$11.17	$162.51	6.88%
2012	$12.59	$163.93	7.68%
2013	$13.31	$164.65	8.08%
2014	$14.28	$165.62	8.62%
2015	$16.34	$167.68	9.74%
2016	$16.20	$167.54	9.67%
2017	$16.94	$168.28	10.06%
2018	$16.46	$167.80	9.81%
2019	$16.20	$167.54	9.67%

We believe the increase to an average residential customer's monthly bill that would result from implementing PEF's Compliance Plan is disproportionately high and clearly constitutes an undue rate impact on PEF's customers. As will be discussed below, Florida Statutes provide a remedy for addressing such cases of conservation plans having an undue impact on customer rates.

PEF's Rate Mitigation Plan

As mentioned in the case background, due to the significant rate impact associated with the initial filing, we also encouraged PEF to submit an alternative DSM Plan to lessen the rate impact over the planning period. The Company's Rate Mitigation Plan does not project achievement of our approved goals for residential customers. Residential goal achievement is forecast at less than 70 percent for each category, including 64.4 percent for summer peak demand, 69.8 percent for winter peak demand, and 48.8 percent for annual energy. However, goals for commercial/industrial customers are projected to be achieved or exceeded in each category under the Rate Mitigation Plan. Even so, combining the savings from the residential and commercial/industrial categories fails to result in the Rate Mitigation Plan meeting the goals we set.

Mitigation Plan Programs

PEF's Rate Mitigation Plan contains the same programs as the Compliance Plan, except that the Technical Potential program in the residential portfolio has been replaced with three programs. Two of these programs, Residential Lighting and Appliance Recycling, were formerly measures within the Technical Potential program and have simply been converted to stand-alone programs. The third program, Residential Behavior Modification, is a newly designed program which will provide reports to customers that allow them to compare their energy use and consumption patterns with that of neighbors in similar homes.

Rate Impact of Mitigation Plan

As discussed above, the costs to implement a DSM program consist of administrative expenses, equipment costs, and incentive payments to the participants, which are recovered by the Company through its ECCR clause. This clause represents a monthly bill impact to customers as part of the non-fuel cost of energy on their bills. Table 4 shows the ECCR Expenditures and Rate Impact on a typical residential customer's bill under the Rate Mitigation Plan over ten years. Under the Rate Mitigation Plan, the monthly bill impact would range from \$4.73 in 2011 to \$6.13 in 2014, when we are due to revisit the conservation goals as required by Section 366.82(6), F.S.

Table 4 - Estimated Rate Impact of PEF's Rate Mitigation Plan Associated with Goals
(1,200 kWh Residential Bill)

Year	ECCR Component (\$/mo)	Estimated Residential Bill (\$/mo)	Percent of Bill (% Bill)
2010	\$3.24	\$154.58	2.10%
2011	\$4.73	\$156.07	3.03%
2012	\$5.20	\$156.54	3.32%
2013	\$5.67	\$157.01	3.61%
2014	\$6.13	\$157.47	3.89%
2015	\$5.98	\$157.32	3.80%
2016	\$5.66	\$157.00	3.60%
2017	\$5.25	\$156.59	3.35%
2018	\$5.05	\$156.39	3.23%
2019	\$4.92	\$156.26	3.15%

As with our finding regarding PEF's Compliance Plan, discussed above, we believe the increase to an average residential customer's monthly bill that would result from implementing PEF's Rate Mitigation Plan is also high and constitutes and undue rate impact on customers. As will be discussed below, Florida Statutes provide a remedy for addressing such cases of conservation plans having an undue impact on customer rates.

Modification and Approval of Demand-Side Management Plan

Section 366.82(7), Florida Statutes, states as follows:

Following adoption of goals pursuant to subsections (2) and (3), the commission shall require each utility to develop plans and programs to meet the overall goals within its service area. The commission may require modifications or additions to

> a utility's plans and programs at any time it is in the public interest consistent with this act. In approving plans and programs for cost recovery, the commission shall have the flexibility to modify or deny plans or programs that would have an undue impact on the costs passed on to customers. . . .

As we noted above, the Compliance Plan filed by PEF is projected to meet the goals we previously established, but at a significant increase in the rates paid by PEF customers. We further noted that PEF's Rate Mitigation Plan is not estimated to meet the goals we established, yet also has a substantial rate increase. After deliberation, we find that both Plans filed by PEF will have an undue impact on the costs passed on to consumers, and that the public interest will be served by requiring modifications to PEF's DSM Plan. Therefore, we hereby determine to exercise the flexibility specifically granted us by statute to modify the Plans and Programs set forth by PEF.

Currently, PEF has an approved Plan as a result of our 2004 goal setting process, and the programs contained in that Plan have yielded significant increases in conservation and decreases in the growth of energy and peak demand. As noted above, both the Compliance Plan and Rate Mitigation Plan substantially rely on these existing Programs, with some modifications, and only a few new programs. We therefore conclude that the Programs currently in effect, even without modification, are likely to continue to increase energy conservation and decrease seasonal peak demand. As further discussed above, the rate impacts of the existing Plan are relatively minor. We find that the Programs currently in effect, contained in PEF's existing Plan, are cost effective and accomplish the intent of the statute. Therefore, exercising the specific authority granted us by Section 366.82(7), F.S., we hereby modify PEF's 2010 Demand-Side Management Plan, such that the DSM Plan shall consist of those programs that are currently in effect today.

We do wish to specifically note that Order No. PSC-10-0605-PAA-EG, while denying the Petition to approve the DSM Plan, did specifically approve six solar pilot programs. Those programs have been implemented to date. Given that they are pilot programs, we believe they should be continued, and reaffirm that provision of Order No. PSC-10-0605-PAA-EG.

Financial Reward or Penalty under Section 366.82(8), Florida Statutes

Section 366.82(8), F.S., gives us the authority to financially reward or penalize a company based on whether its conservation goals are achieved, at our discretion. In Order No. PSC-09-0855-FOF-EG, we concluded that, "[w]e may establish, through a limited proceeding, a financial reward or penalty for a rate-regulated utility based upon the utility's performance in accordance with Section 366.82(8) and (9), F.S."

As a result of our decision to modify PEF's 2010 Plan, we wish to clarify that PEF shall not be eligible for any financial reward pursuant to these statutory sections unless it exceeds the goals set forth in Order No. PSC-09-0855-FOF-EG. Conversely, PEF shall not be subject to any financial penalty unless it fails to achieve the savings projections contained in the existing DSM plan, which is approved and extended today.

Closure of Docket

By our vote today, we have taken action to approve a DSM Plan and continue existing Programs for PEF. If no person whose substantial interests are affected by this proposed agency action files a protest within 21 days of the issuance of this Order, we will issue a Consummating Order, and the docket shall be closed. If a protest is filed within 21 days of the issuance of this Order, however, the docket shall remain open to resolve the protest.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s November 29, 2010, Original Goal Scenario DSM Plan and Revised Goal DSM Plan are not approved as filed. It is further

ORDERED that a Modified DSM Plan, consisting of existing Programs currently in effect, as detailed in the body of this Order, is Approved. It is further

ORDERED that Progress Energy Florida, Inc. shall only be eligible for a financial reward or penalty pursuant to Section 366.82(8) and (9), Florida Statues as set forth in the body of this Order. It is further

ORDERED that the Solar Pilot Programs approved in Order No. PSC-10-0605-FOF-EG are continued. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that upon the issuance of a Consummating Order, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 16th day of August, 2011.

/s/ Ann Cole
ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

LDH

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on September 6, 2011.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Appendix D - Descriptions of Proposals

(Pages 1 through 5)

REDACTED

This document is confidential in it’s entirety

Duke Energy Florida, Inc.
Ten-Year Site Plan

April 2014

2014-2023

Submitted to:
Florida Public Service Commission

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TABLE OF CONTENTS (Continued)

LIST OF REQUIRED SCHEDULES

LIST OF

TABLES AND FIGURES

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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.

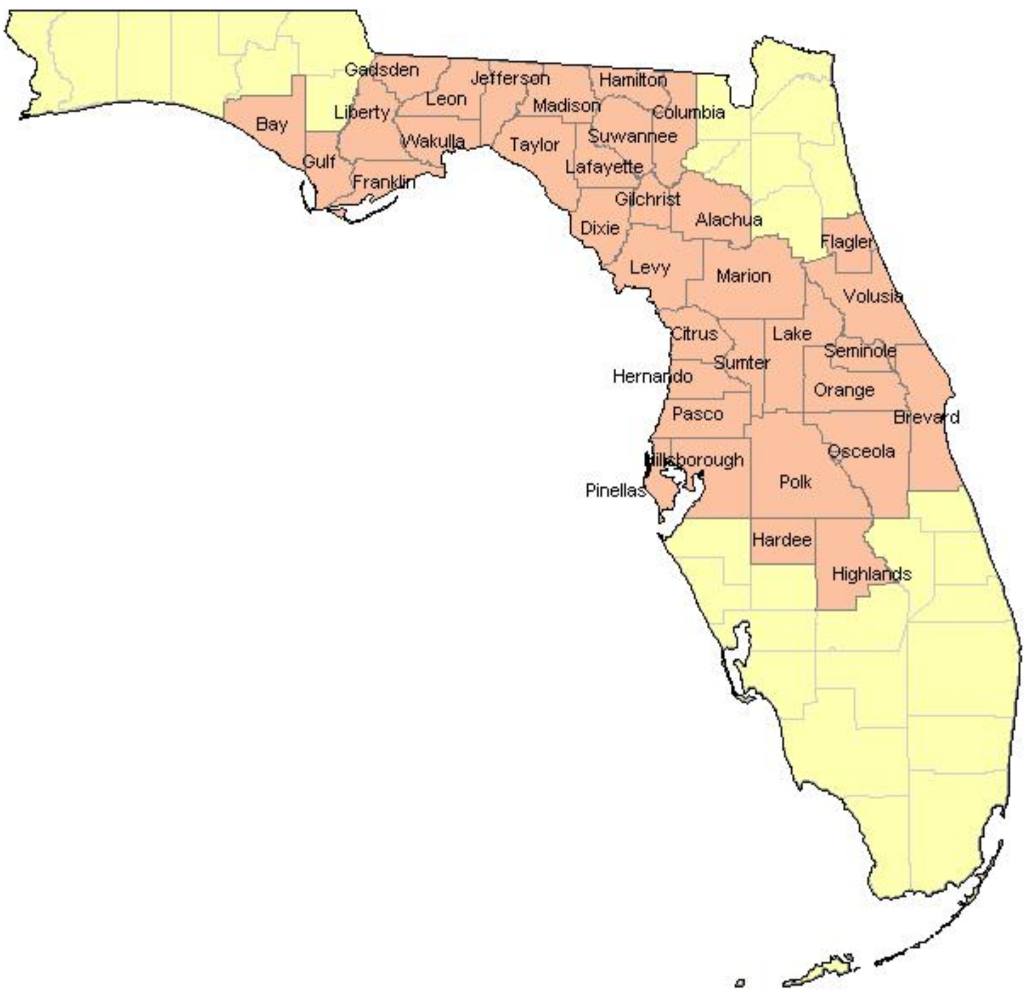
ENERGY MANAGEMENT and ENERGY EFFICIENCY

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)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	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) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) 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.

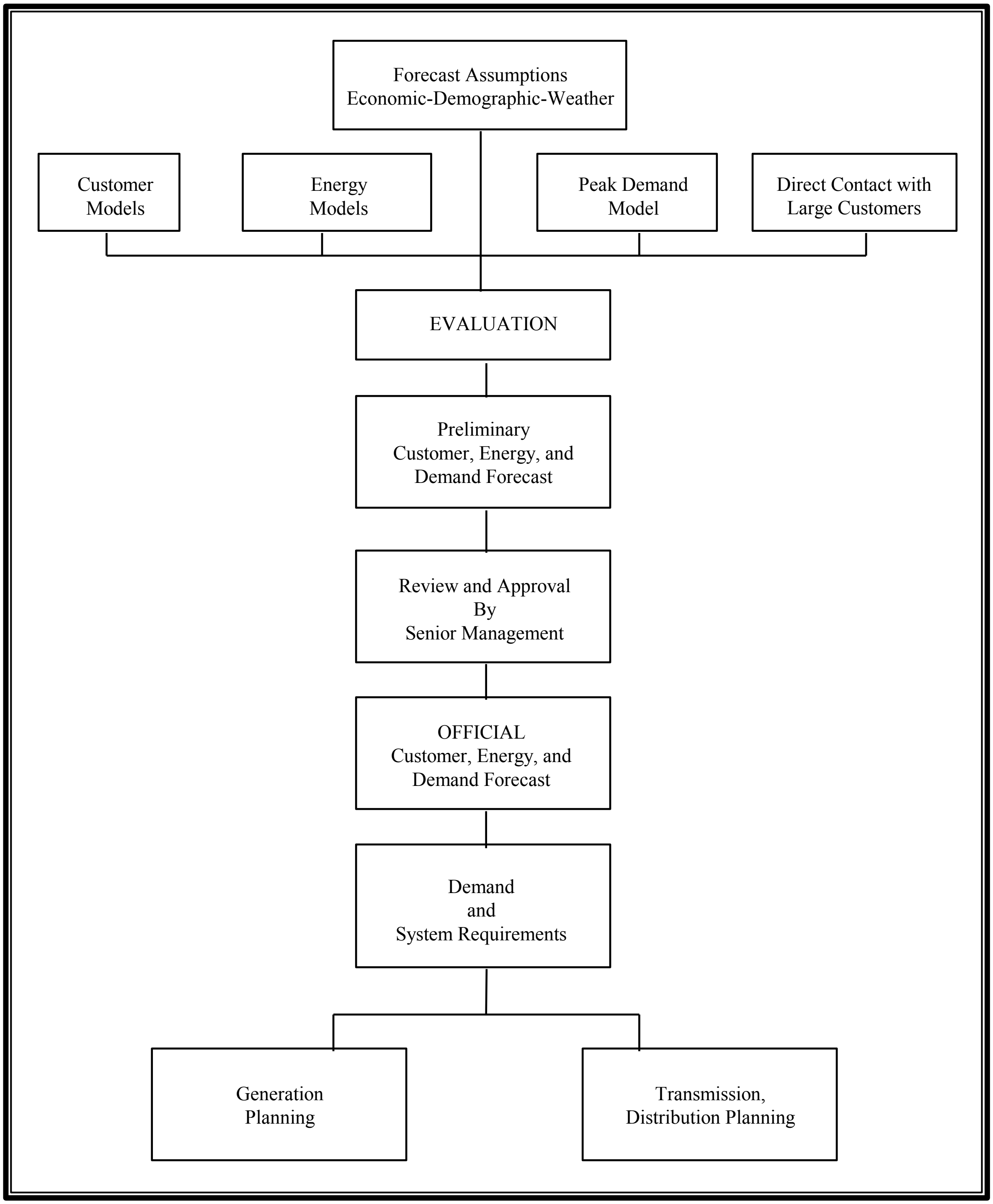
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for 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.

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

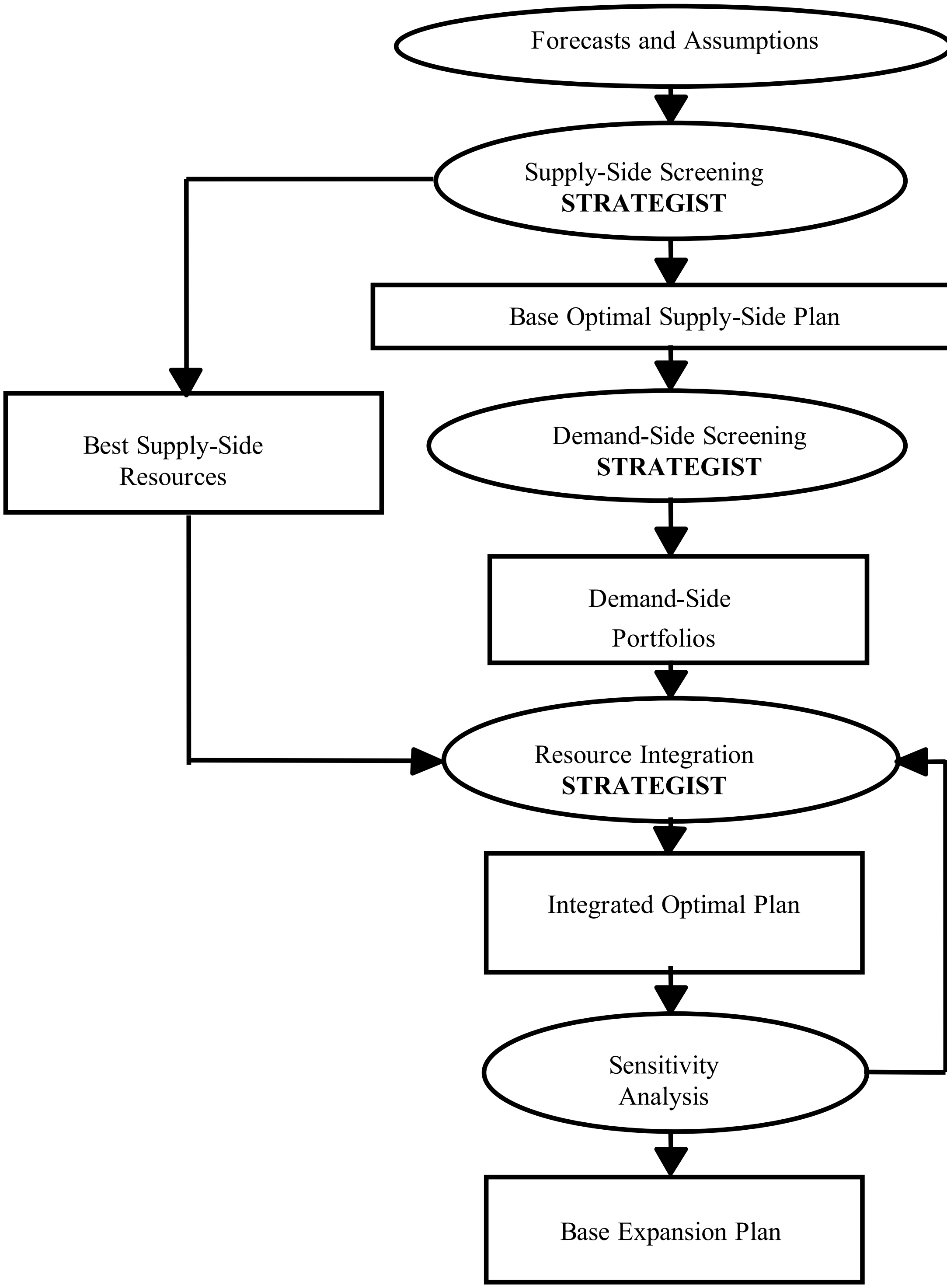
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide 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

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.

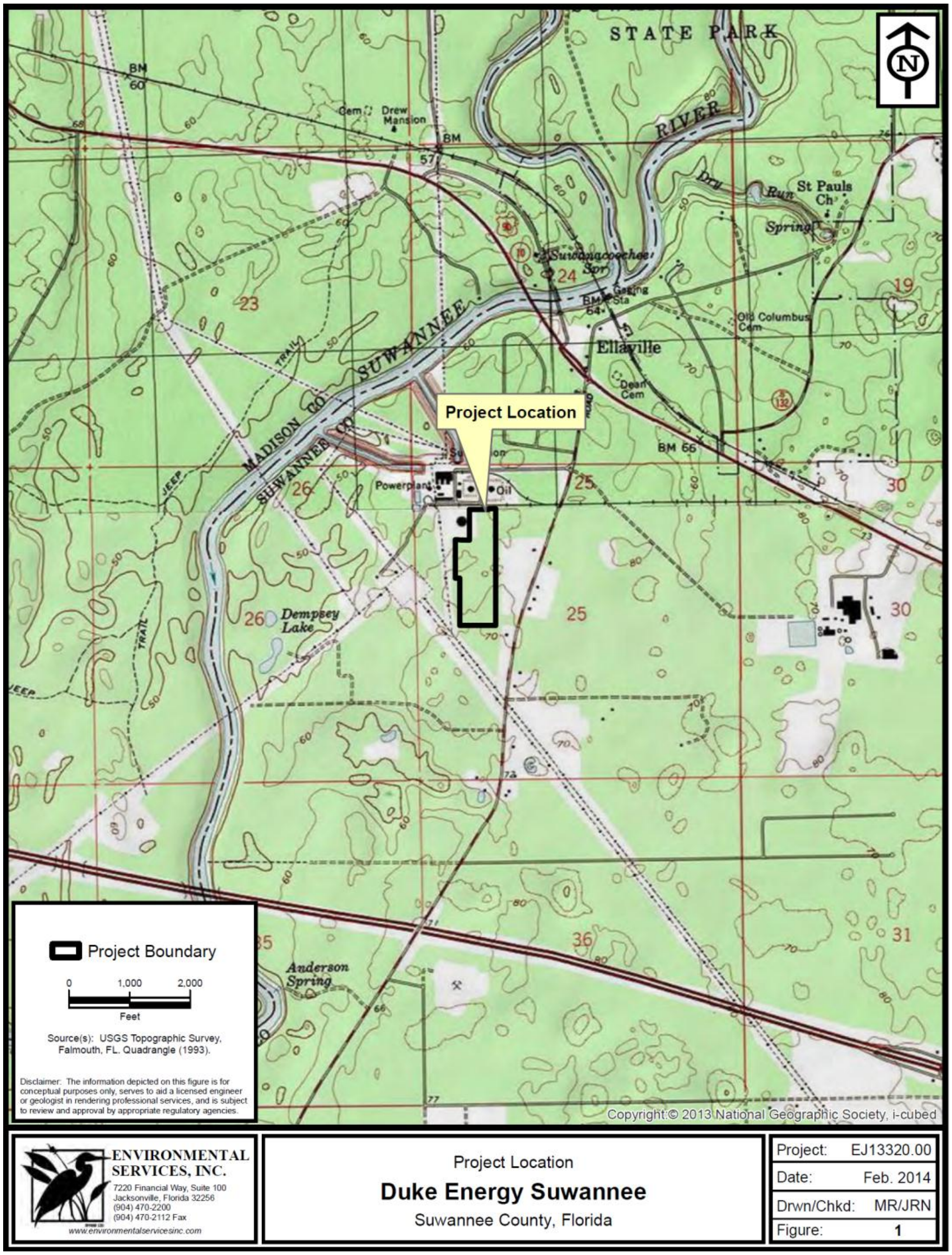
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. 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



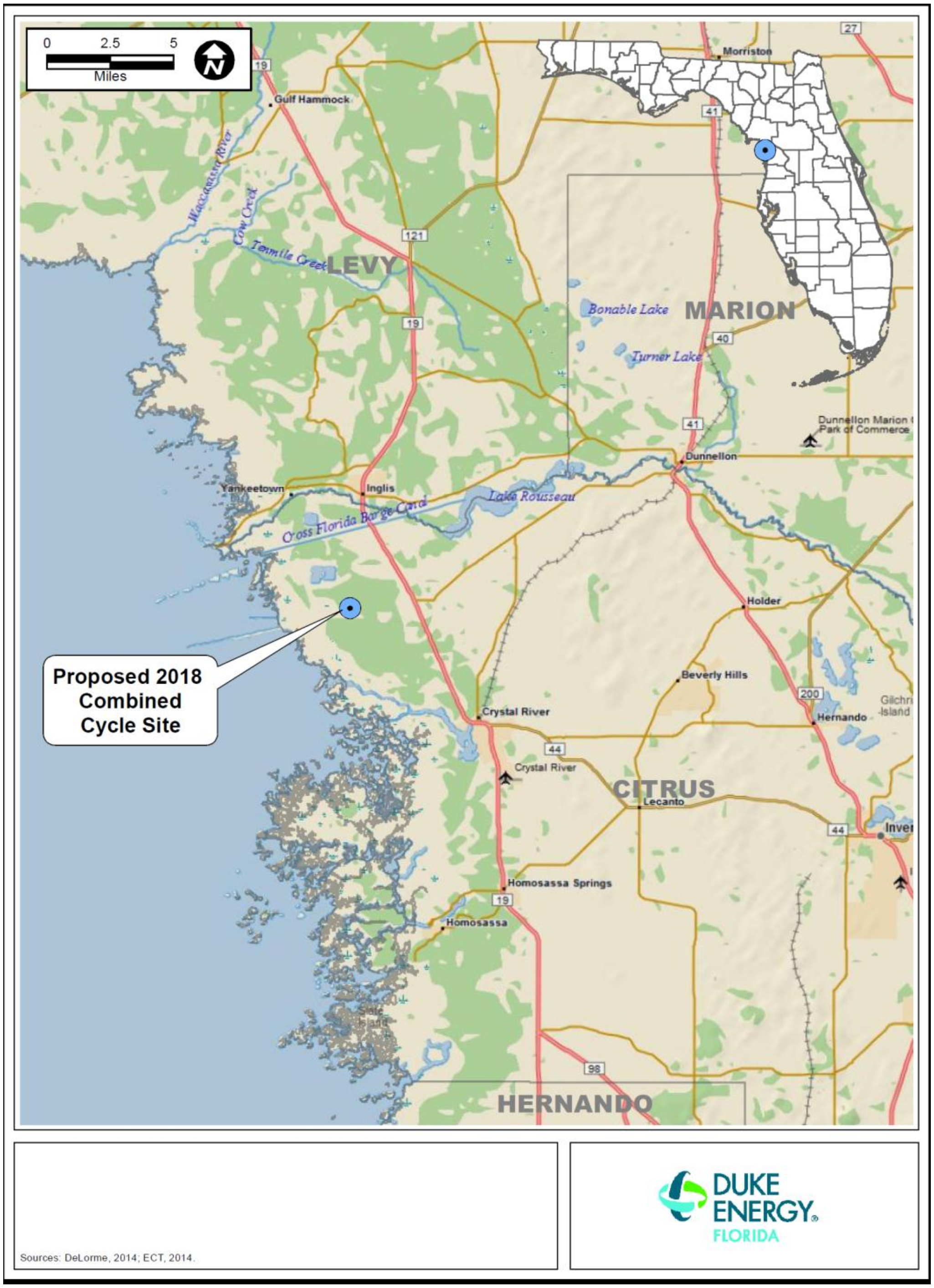
CITRUS COUNTY

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



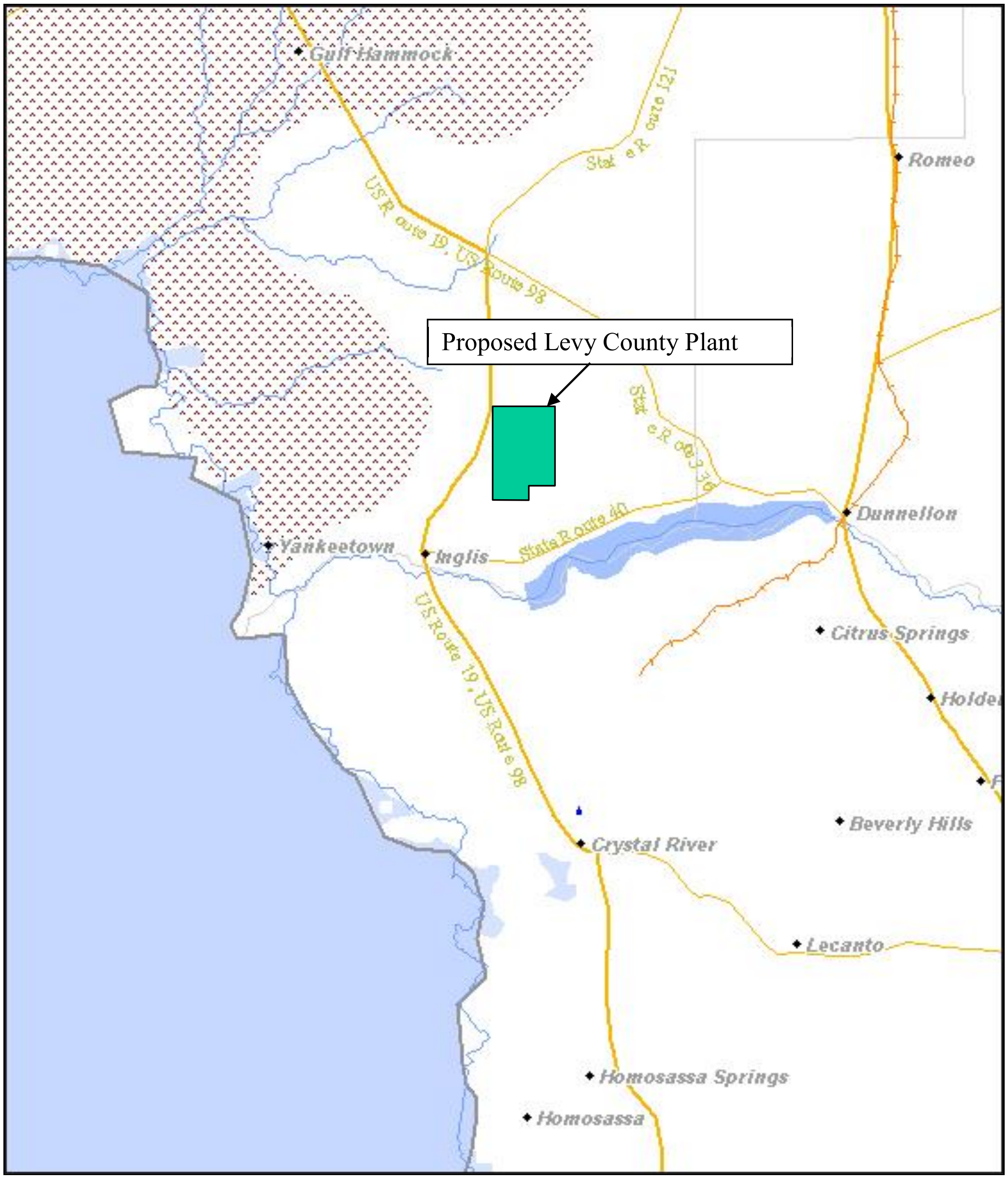
LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

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)



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		With Citrus CC		Without Citrus CC	
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%	11,012	20.4%
2017	9,307	11,232	20.7%	11,232	20.7%
2018	9,439	11,362	20.4%	10,542	11.7%
2019	9,813	12,132	23.6%	10,492	6.9%
2020	9,935	12,027	21.1%	10,387	4.5%

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DOCKET: 140110-EI EXHIBIT: 50
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-3 (140110)

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DEF's projected net energy for load growth on DEF's system

	LOAD FORECAST		
	Firm 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
2018	9,544	9,439	41,995
2019	9,639	9,813	43,013
2020	9,971	9,935	43,998
2021	10,059	9,952	44,419
2022	10,144	10,067	44,870
2023	10,225	10,173	45,459

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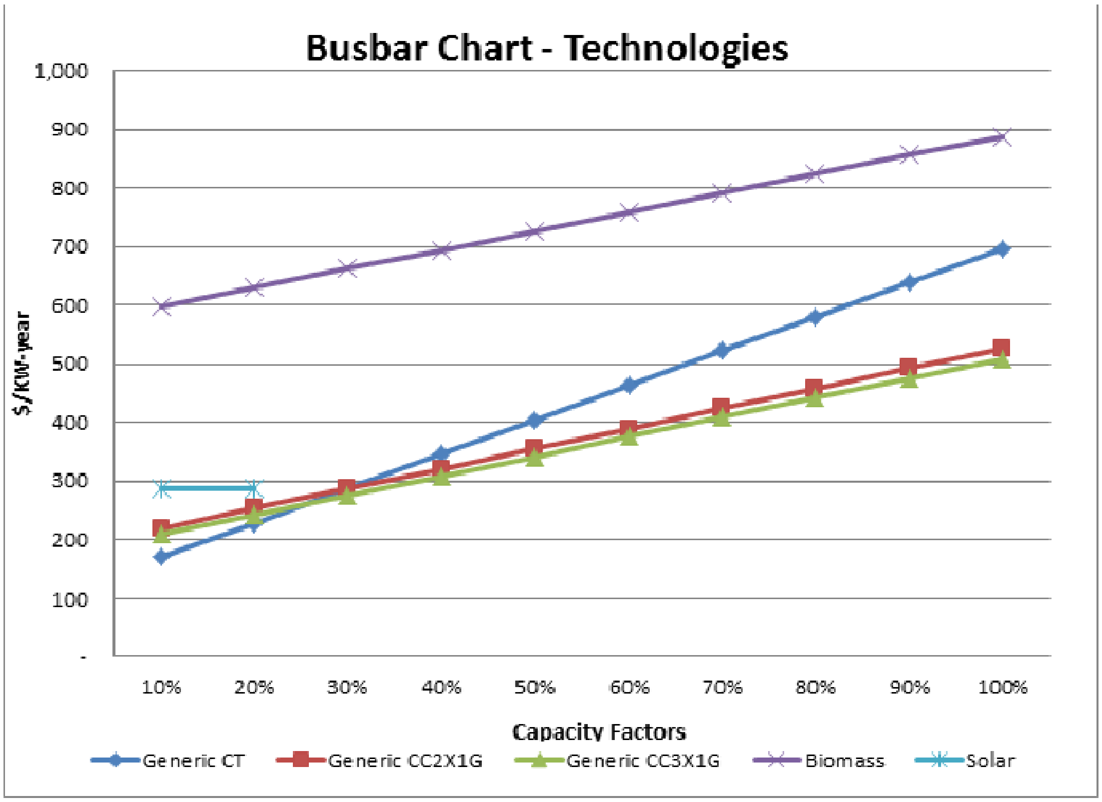
BUSBAR COST COMPARISON



Alternative	Summer Total Capacity	Overnight Generation Capital Costs 2016$		Overnight Transmission Capital Costs 2016$		O&M Costs 2016$		Summer Heat Rate	Equivalent FOR	Fuel Type
						Fixed	Variable			
	(MW)	$/Kw	$M	$/Kw	$M	$/Kw	$/Mwh	Btu/Kwh	(%)	
Combustion Turbine	186.66	457	85	142	27	72	10.89	10,343	2.05%	Gas / Oil
Combined Cycle 2x1 G	792.97	904	717	392	311	72	5.72	6,800	6.36%	Gas / Oil
Combined Cycle 3x1 G	1,189.10	870	1,035	349	414	70	4.83	6,820	6.36%	Gas / Oil
Biomass	50.00	4,588	229	124	6	111	5.75	13,000	6.80%	Wood
Solar Photovoltaic	25.00	1,956	49	124	3	89	-	-	-	Solar

* O&M Fixed Costs include Gas Reservation Charges

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DOCKET: 140110-EI EXHIBIT: 52
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DESCRIPTION: Benjamin M.H. Borsch
BMHB-5 (140110)

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Duke Energy Florida
Exhibit No. ____________ (BMHB-6)
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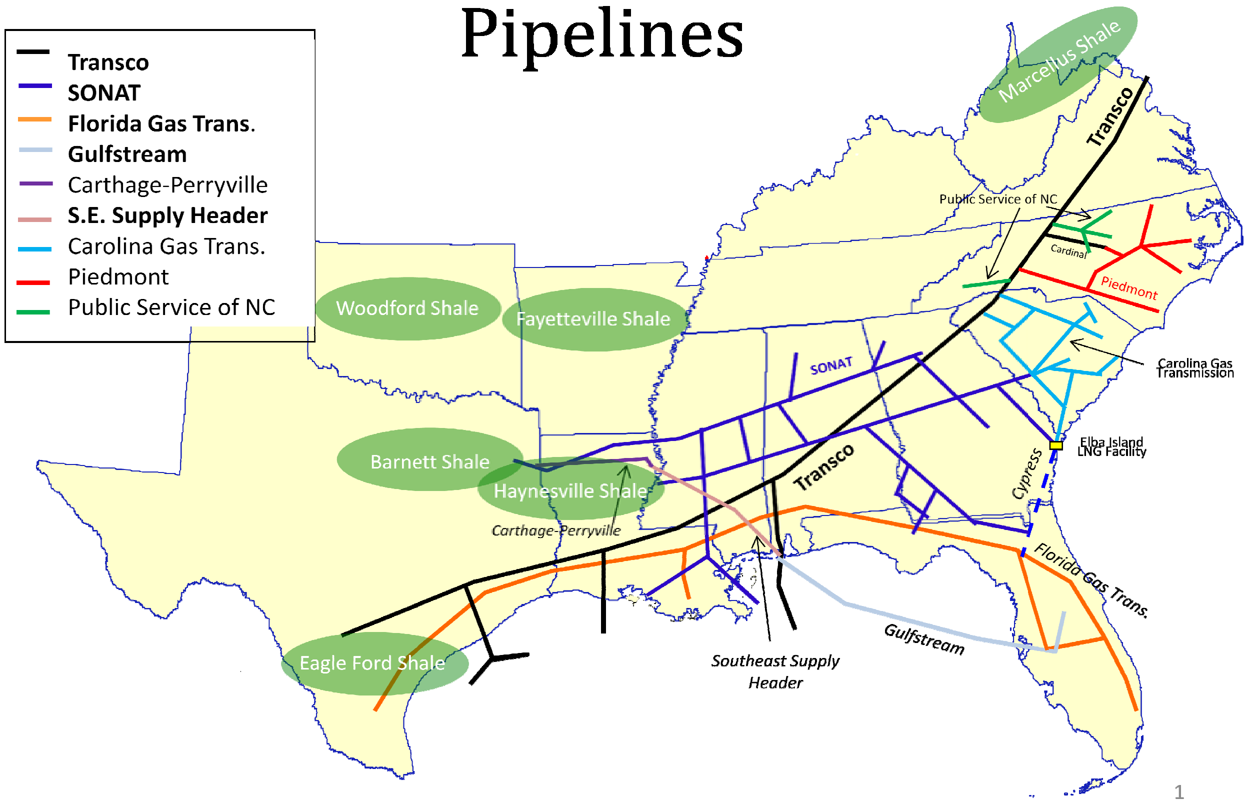
Location of Unconventional Shale Gas Developments and Table of the Current and Expected Gas Production From These Shale Gas Plays

Major Southeast Natural Gas Pipelines



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DOCKET: 140110-EI EXHIBIT: 53
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-6 (140110)

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Duke Energy Florida
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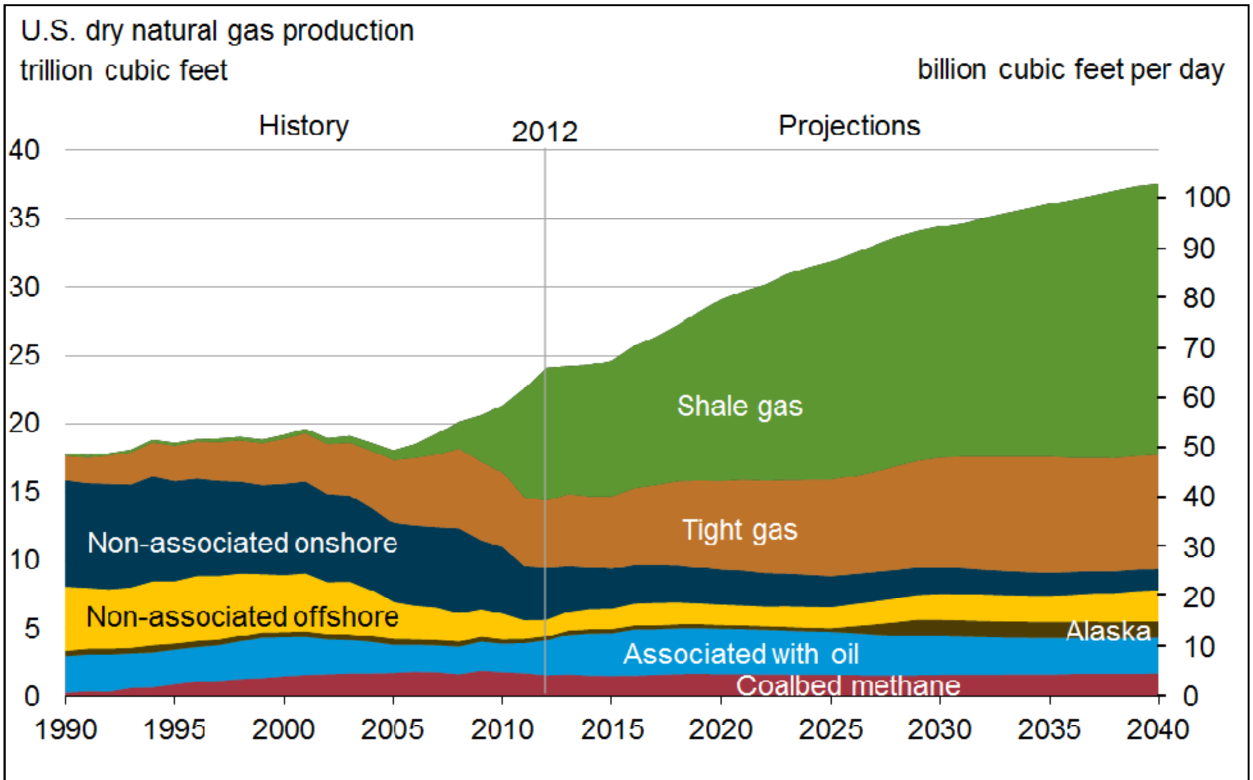
Table of the Current and Future Production from Both Conventional and Unconventional Gas Supply Resources



Source: EIA, Annual Energy Outlook 2014, Reference case

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DESCRIPTION: Benjamin M.H. Borsch
BMHB-7 (140110)

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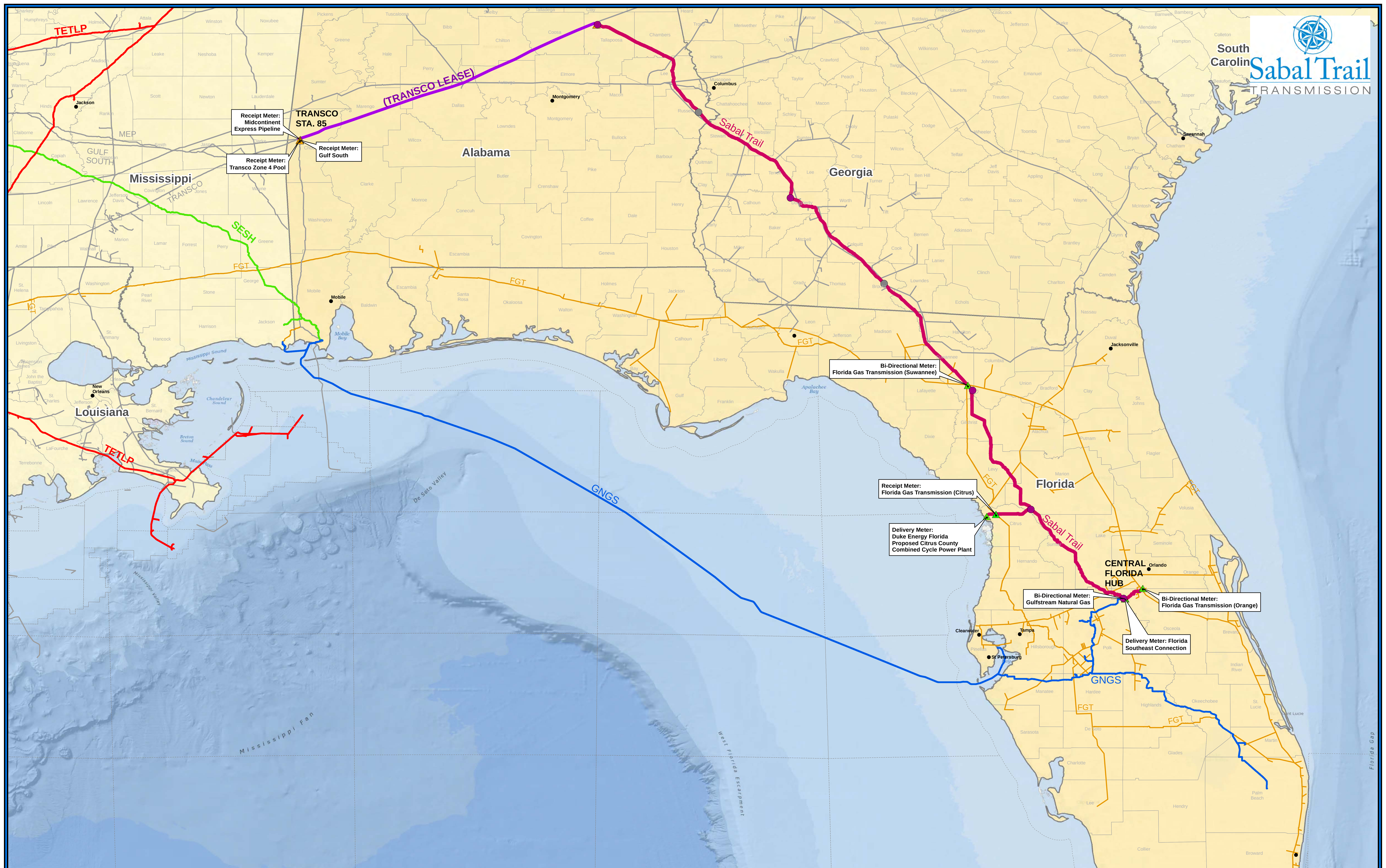
Sabal Trail Transmission LLC Natural Gas Pipeline



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PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-8 (140110)

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2018 RFP Evaluation Process

Step 1
Screening for Threshold Requirements

Step 2
Initial Evaluation

Preliminary Economic Bid Screening
Minimum Technical Requirements

Step 3
Selection of Short List

Step 4
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Initial Detail Evaluation:
Optimization Analysis
Technical Evaluation
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Final Detail Evaluation:
Detail Resource Plan Comparisons
Scenarios
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Step 5
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Contract Development
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Transmission Feasibility
Transmission Impact Studies
Transmission Facilities Studies

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 56
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-9 (140110)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 57
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-10 (140110)

Threshold Requirements

A. General Requirements

- The proposal is received on time.
- The proposal submittal fee is received by DEF.
- The pricing schedules are properly specified and the proper price indices are used.
- Power must be available for delivery under the contract May 1, 2018
- The proposed contract end date is no earlier than April 30, 2033

B. Operating Performance Thresholds

- If the project is located in DEF's system, the Bidder's proposal will be required to show documentation that the following operational criteria can be meet:
  - to operate the project to conform with DEF's ***Voltage Control*** requirements.
  - to operate the project to conform with DEF's ***Frequency Control*** requirements.
  - to be ***Fully Dispatchable*** and install ***Automatic Generator Control*** ("AGC") that is tied into DEF's Energy Control Center **[New and Existing Unit Proposals]**.
- If the project is located outside of DEF's system, New and Existing Unit Proposals must provide documentation to show that the proposal is ***Fully Dispatchable*** and provide ***Dynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.
- The Bidder must show documentation they are willing to ***coordinate the project's maintenance scheduling*** with DEF.
- System Power Proposals must show documentation that the proposal is ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). System Power Proposals must also provide D***ynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.

C. Terms & Conditions Thresholds

- Bidders must agree to each of the Terms & Conditions identified in Attachment A.

  \- OR -
- If Bidder has any objections to the Terms & Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

D. Site Control Thresholds [New and Existing Unit Proposals]

- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title (or long term lease) and legal description of the property is required for **Existing Unit Proposals**.

E. Transmission Threshold

- If the proposal is for resources located outside of DEF's system, the Bidder must provide a transmission plan that exclusively utilizes firm transmission service from the host system to the DEF system. Bidders must provide evidence that the host system is willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals. Bidders must provide host utility documentation that the results of a generator feasibility study and/or a host transmission system impact study performed by the host system will be completed or documentation such as a transmission study agreement showing that the results will be available no later than 30 days following the bid submittal date.
- For New Unit Proposals physically located inside the DEF system, documentation that the required Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT has been submitted to DEF **[New Unit Proposals]**.
- The Transmission Information Schedule (Schedule 7 of the Response Package) is properly completed for **All Proposals**.

Minimum Technical Requirements

A. Environmental

* Preliminary environmental analysis performed and submitted to DEF [New Unit Proposals].
* Reasonable schedule for securing permits presented with evidence provided that it is reasonable to expect that permits can be secured in a timely fashion [New Unit Proposals].

B. Engineering and Design

* The project technology is capable of achieving the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].
* Operation and Maintenance Plan provided that indicates the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. Fuel Supply and Transportation Plan

* Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. Project Financial Viability

* For New Unit Proposals, evidence provided that it is reasonable to expect that the project is financially viable (assuming a power purchase agreement is in place with DEF) [New Unit Proposals].
* Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. Project Management Plan

* For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial within the time frame requirements of this RFP [New Unit Proposals].

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Duke Energy Florida
Exhibit No. _______ (BMHB-12)
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Table of 2018 RFP Bidder Proposal Resource Scenarios Evaluated in the Company's 2018 RFP Evaluation Process

Scenario	Bid Units	Generic 2018 Units	Backfill Units
1	Citrus CC (NPGU)	None	None
3	Bid C1 Bid A Bid G Bid B	2 CT (188MW each)	2034 450 MW CC 2043 450 MW CC 2044 450 MW CC
5	Bid A Bid G	2x1 CC (793 MW)	2043 450 MW CC 2044 450 MW CC
6	Bid C1 Bid A	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
7	Bid C1 Bid G Bid B	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
8	Bid A	2x1 CC (793 MW) 2 CT (188MW each)	2043 450 MW CC
9	Bid G	2x1 CC (793 MW) 2 CT (188MW each)	2044 450 MW CC
10	Bid C1	2x1 CC (793 MW) 2 CT (188MW each)	2034 450 MW CC
11	Citrus CC (NPGU) Bid B	None	None

Table of the Results of the Company's Initial Detailed Evaluation of the 2018 RFP Bidder Proposal Resource Scenarios

		Differential vs. NPGU $M CPVRR		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($951)	($908)	($773)
TP 5	Bids A and G + Generic CC	($583)	($569)	($438)
TP 6	Bids A and C1 + Generic CC	($512)	($510)	($466)
TP 7	Bids B, C1, and G + Generic CC	($685)	($646)	($620)
TP 8	Bid A + 2 Generic CTs + Generic CC	($376)	($366)	($171)
TP 9	Bid G + 2 Generic CTs + Generic CC	($647)	($631)	($403)
TP 10	Bid C1 + 2 Generic CTs + Generic CC	($457)	($444)	($308)
TP 11	Self-Build NPGU and Bid B	($20)	($4)	($50)

Results of all the Company's Detailed Evaluations of the 2018 RFP Bidder Proposal Resource Scenarios

		Differential CPVRR $2014 in $Millions		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($1,218)	($1,171)	($1,037)
TP 5	Bids A and G + Generic CC	($748)	($731)	($600)
TP 6	Bids A and C1 + Generic CC	($705)	($699)	($655)
TP 7	Bids B, C1, and G + Generic CC	($847)	($811)	($784)
TP 8	Bid A + 2 Generic CTs + Generic CC	($477)	($464)	($269)
TP 9	Bid G + 2 Generic CTs + Generic CC	($718)	($693)	($464)
TP 10	Bid C1 + 2 Generic CTs + Generic CC	($548)	($535)	($399)
TP 11	Self-Build NPGU and Bid B	($29)	($13)	($59)

Docket No. ___________
Duke Energy Florida
Exhibit No. ________ (BMHB-1)
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FRCC
Florida Reliability Coordinating Council, Inc.

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**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 62
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-1 (140111)

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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.

<u>Study Methodology</u>

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.

DEF is currently developing plans to have the corridor located north of Orlando 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.

<u>Deliverable 3 - Reliability impact of a new combined cycle built at Crystal River in 2018</u>

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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TABLE OF CONTENTS (Continued)

LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

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.

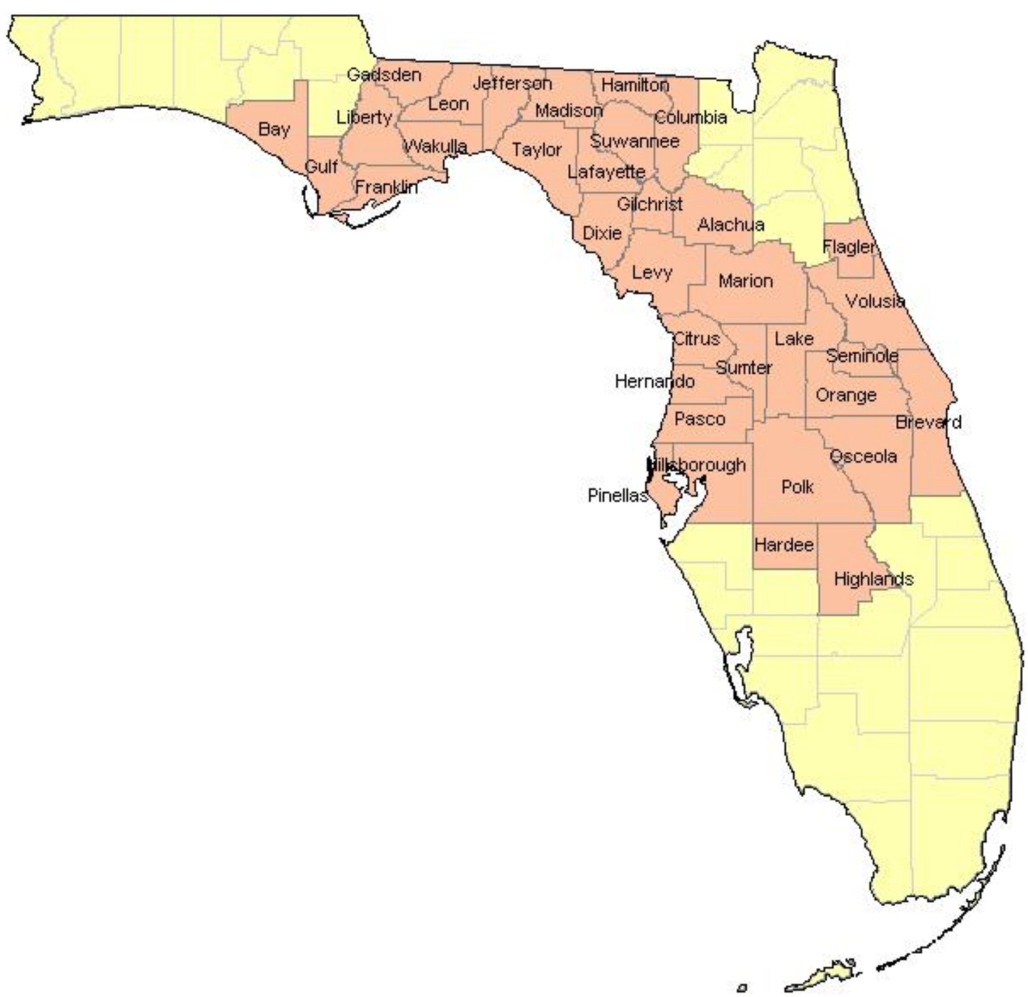
ENERGY MANAGEMENT and ENERGY EFFICIENCY

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)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	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) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) 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) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) 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.

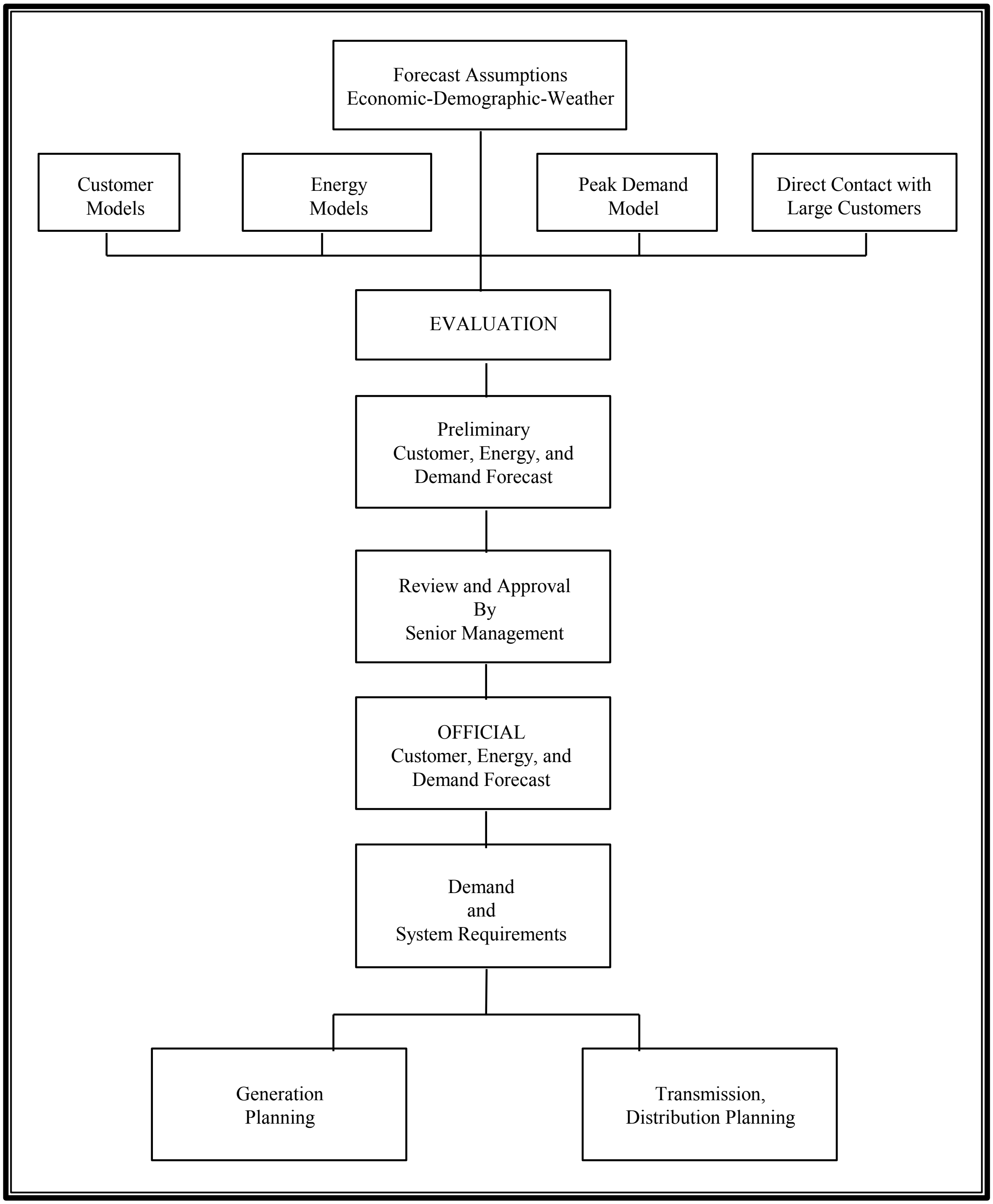
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for 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.

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

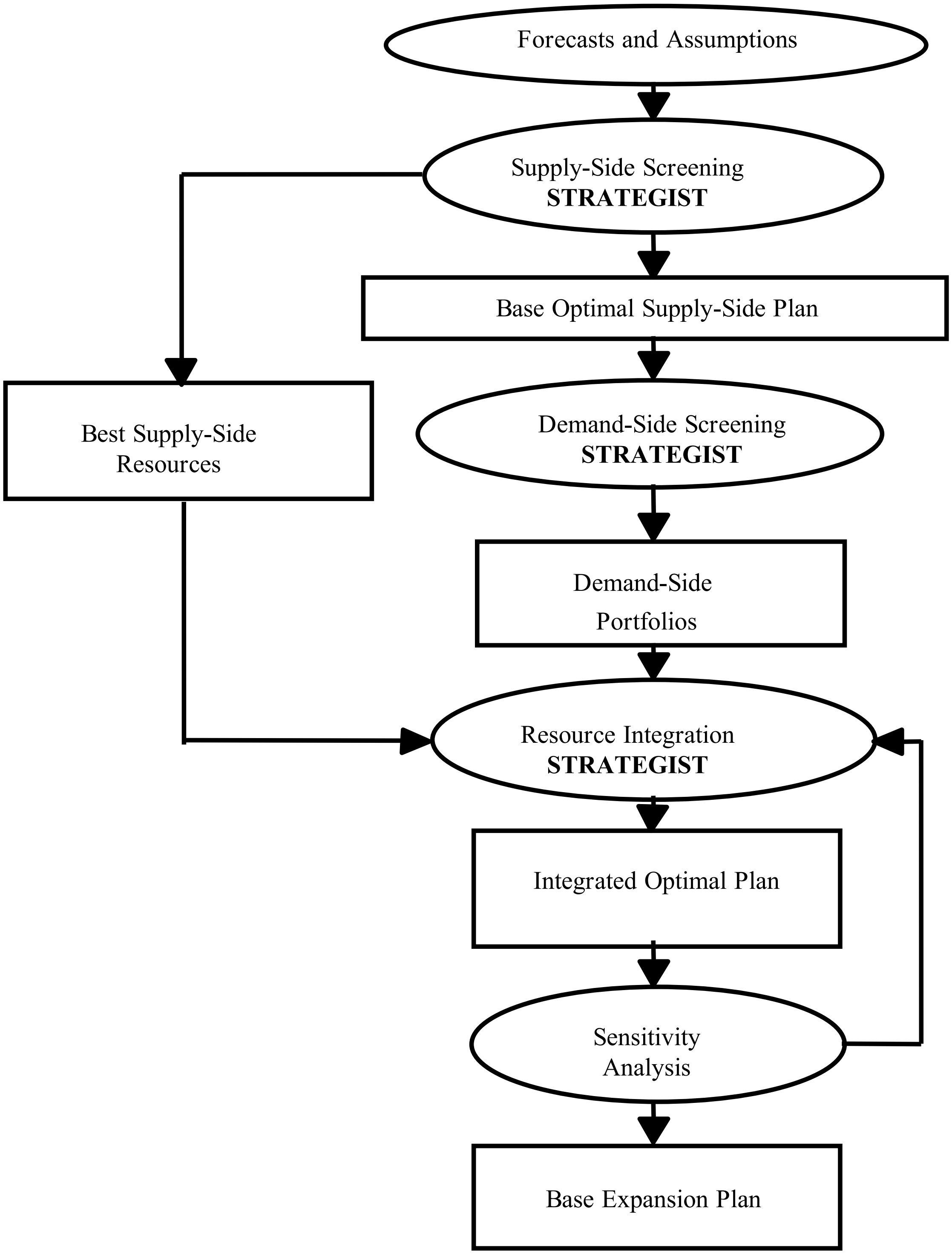
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide 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

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.

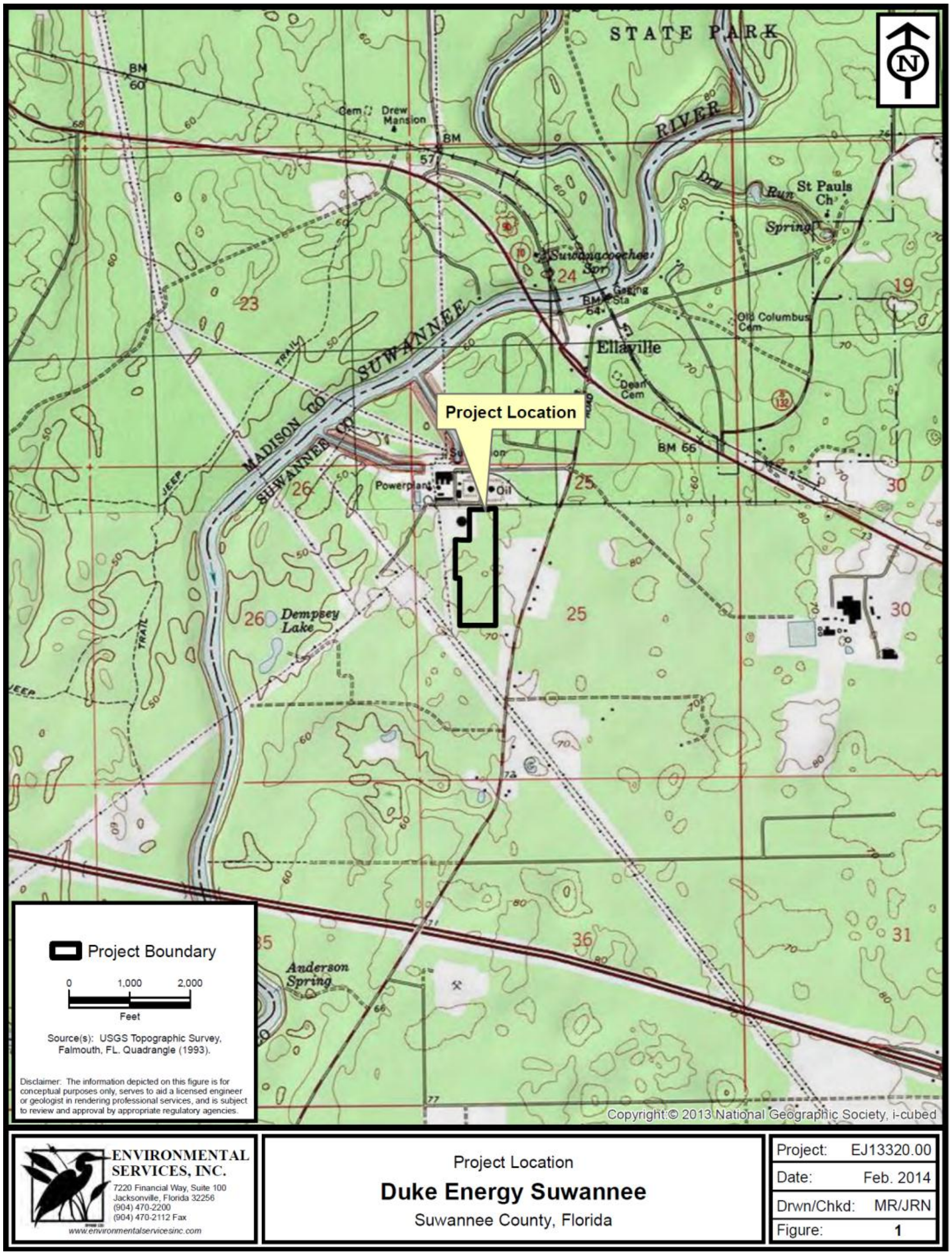
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. 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



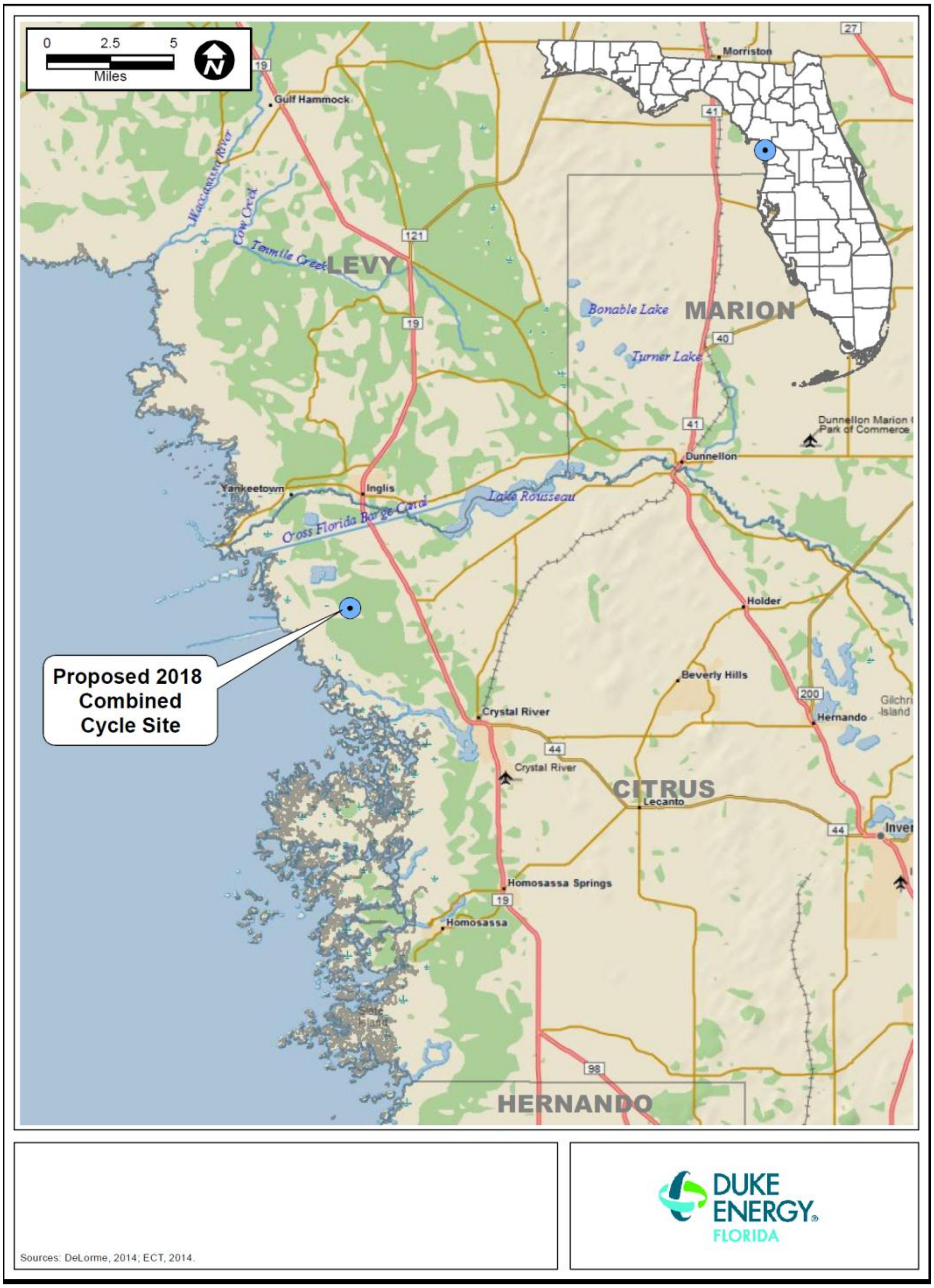
CITRUS COUNTY

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



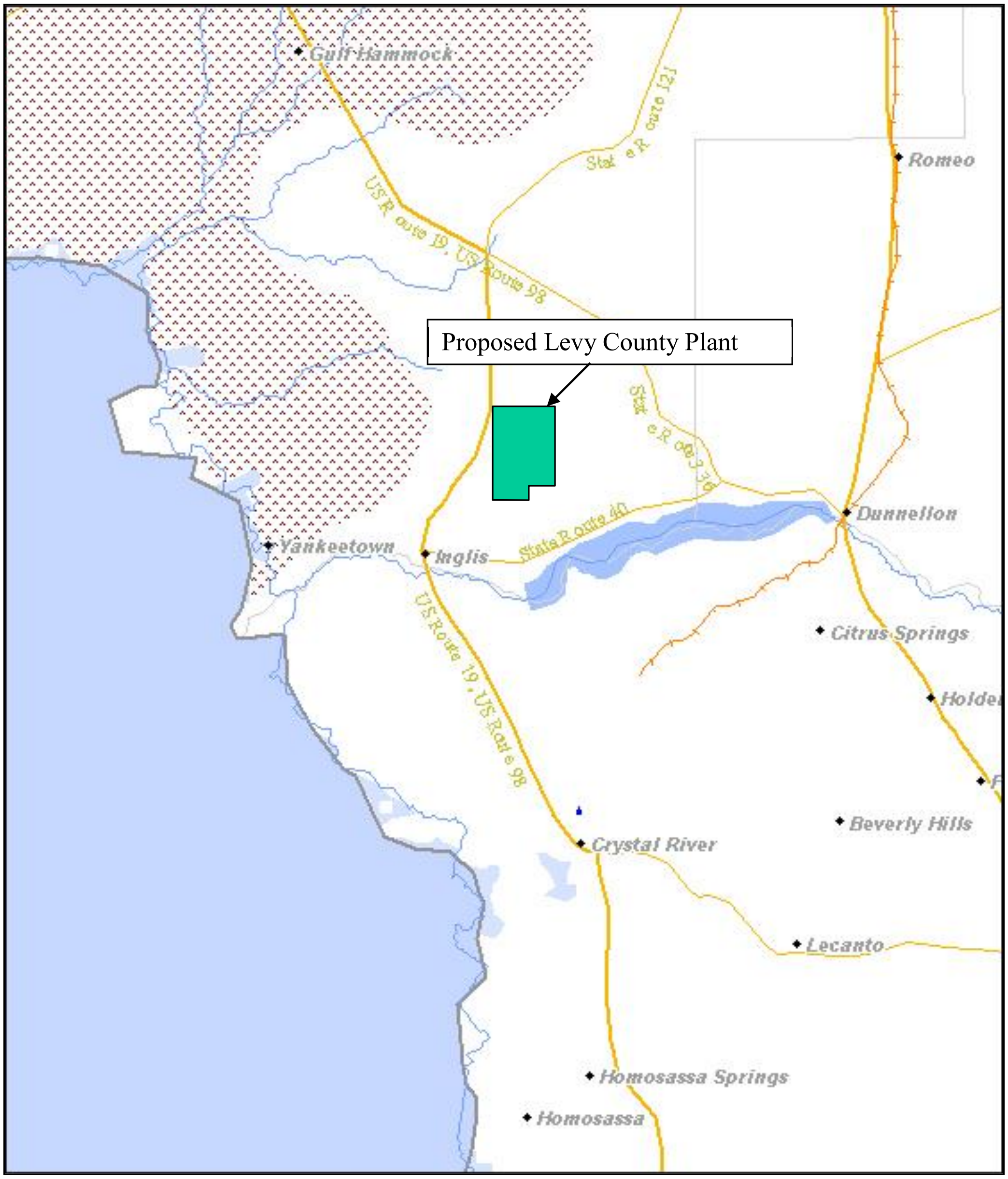
LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

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)



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

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%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 65
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-4 (140111)

Docket No. ____________
Duke Energy Florida
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Page 1 of 1

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%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 66
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-5 (140111)

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

REDACTED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 68
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-7 (140111)

Docket No. ____________
Duke Energy Florida
Exhibit No. ____ (BMHB-7)
Page 1 of 1

[redacted]

EXHIBIT WITHDRAWN FROM HEARING

EXHIBIT WITHDRAWN FROM HEARING

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 71
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-10 (140111)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 72
PARTY: DUKE ENERGY FLORIDA, INC. – (DIRECT)
DESCRIPTION: Benjamin M.H. Borsch BMHB-11 (140111)

Exhibit PJH-1
Curriculum Vitae

Paul J. Hibbard
Vice President

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111 Huntington Ave.
Tenth Floor
Boston, MA 02199

EDUCATION

Ph.D. program (coursework), Nuclear Engineering, University of California, Berkeley

M.S. in Energy and Resources, University of California, Berkeley
Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs

B.S. in Physics, University of Massachusetts, Amherst

PROFESSIONAL EXPERIENCE

2010 - Present Analysis Group, Inc., Boston, MA
Vice President

2007 - 2010 MA Department of Public Utilities, Boston, MA
Chairman
Member, Energy Facilities Siting Board
Manager, New England States Committee on Electricity
Treasurer, Executive Committee, Eastern Interconnect States' Planning Council
Representative, New England Governors' Conference Power Planning Committee
Member, NARUC Electricity Committee, Procurement Work Group

2003 - 2007 Analysis Group, Inc., Boston, MA
Vice President
Manager ('03 – '05)

2000 - 2003 Lexecon Inc., Cambridge, MA
Senior Consultant
Consultant ('00 – '02)

1998 - 2000 Massachusetts Department of Environmental Protection, Boston, MA
Environmental Analyst

1991 - 1998 Massachusetts Department of Public Utilities, Boston, MA
Senior Analyst, Electric Power Division

1988 - 1991 University of California, Berkeley, CA
Research Assistant, Safety/Environmental Factors in Nuclear Designs

OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Advanced Energy Economy (2011).

SELECTED REPORTS, TESTIMONY AND PRESENTATIONS

"Project Vigilance: Value of Ambri Batteries at Joint Base Cape Cod," Presentation to Raab Restructuring Roundtable, Boston MA, June 2014.

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"The Electric Generation Landscape – A Marathon of Challenges," Presentation to SNL Generation Landscape, Chicago IL, October 2012.

"Economics, EPA, and Old Capacity…Bring Out Your Dead," Presentation to LSI Energy in the Northeast, Boston MA, September 2012.

Hibbard, Paul J., *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, Report to the U.S. Environmental Protection Agency on behalf of Calpine Corporation, August 2012.

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"Economic Impacts of RGGI: Following the Dollars," presentation (with Sue Tierney) to the California Business Climate Network, February 2012.

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"Competitive Markets and Wind Power: Challenge and Opportunity," presented to the Governors' Wind Energy Coalition, Washington DC, November 2011.

Hibbard, Paul J., Susan F. Tierney, Andrea M. Okie and Pavel G. Darling, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States; Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*, November 15, 2011.

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"Interdependence and Opportunity: The Growing Link Between Electricity and Natural Gas," presentation to the COGA Energy Epicenter Conference, Denver CO, August 2011.

"Potomac River Generating Station: Update on Reliability and Environmental Considerations," with Pavel Darling and Susan Tierney, July 19, 2011.

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"The Balancing Act: Challenges in Traversing the Modernization of New England's Infrastructure," presentation to NECA Annual Conference, Mystic CT, May 2011.

"Renewables v. Gas: The Future of New England Infrastructure," presentation to the EBC Energy Seminar, Waltham, MA, April, 2011.

"Upcoming Power Sector Environmental Regulations: Framing the Issues About Potential Reliability/ Cost Impacts," presentation to Raab Restructuring Roundtable, Boston MA, October 2010.

"Carbon Regulation: Action and Convergence Spanning the Pond," presentation to Energy Smart Conference, Boston MA, October 2010.

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"Energy Infrastructure Challenges in the Current Policy Environment, A Wide Angle Point of View," presentation to NARUC, Providence RI, September 2010.

"Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," with Susan F. Tierney, Michael J. Bradley, Christopher Van Atten, Amlan Saha, and Carrie Jenks. August 2010.

"Renewables Development – National Policies, New England Progress," presentation to National Association of State Energy Officials Annual Meeting, Boston MA, September 2010.

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"Renewables in the Northeast – Local Opportunities, National Context," presentation to Council of State Governments, Portland ME, August 2010.

"Deregulation and Sustainable Energy," class lecture, MIT (Jonathan Raab Energy Course), Cambridge MA, March 2010.

"Transmission for Renewables," presentation to Raab Restructuring Roundtable, Boston MA, March 2010.

"Federal Transmission Legislation," comments to Capitol Hill Briefing of the Coalition for Fair Transmission Policy, Washington DC, April 2010.

"Transmission Planning & Cost Allocation Alternatives under Order 890," comments to the Energy Bar Association's 64th Meeting, Washington DC, April 2010.

"US Electric Power Transmission: The Battle of the Jurisdictions," comments to CERAWeek 2010, March, 2010.

"New England Blueprint and the Federal Context," presentation to ISO-NE Consumer Liaison Group Meeting, Westborough MA, February 2010.

"Interconnection-Wide Planning and Renewable Energy," comments to the National Wind Coordinating Collaborative, Transmission Update Briefing, December 2009.

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"Renewable Energy Development – The Role of Markets and Planning," presentation to Northeast Power Planning Council General Meeting, Cambridge MA, September, 2009.

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"Conversation With Chairman Hibbard," presentation to New England Energy Alliance, Boston MA, September, 2008.

"Creating the Path: Delivering Clean Energy through Transmission Improvements," presentation to ISO-NE Lights, Power, Action Conference, Boston MA, September, 2008.

"Distributed Resources, the Decoupling Model, and the Green Communities Act," presentation to Raab Restructuring Roundtable, Boston MA, September, 2008.

"Resource Planning: The Contribution of Efficiency and Renewables in Massachusetts," presentation to Law Seminars International Renewable Energy in New England Conference, Boston MA, September 2008.

"Remarks to Economic Studies Working Group," ESWG Committee Meeting, Westborough MA, July 2008.

"Power Trade: Market Context and Opportunities," presentation to New England Governors' Council/Eastern Canadian Premiers' Energy Dialogue, Montreal Canada, May 2008.

"New England Transmission Investment," presentation to Municipal Electric Association of Massachusetts Annual Business Meeting, North Falmouth MA, April 2008.

"Bringing Power from the North," presentation to the Raab Restructuring Roundtable, Boston MA, February 2008.

"Natural Gas: Drivers of Supply, Demand, and Prices," comments to Guild of Gas Managers, November 2007.

"Generation and Demand Outlook for New England," presentation to NECA Dinner Meeting, Cambridge MA, September, 2007.

"Comments on ISO's Draft Regional System Plan," presentation to ISO Planning Advisory Committee, Boston MA, September 2007.

"Regulatory Pressures, Policy Opinions," presentation to Environmental Business Council, Boston MA, July 2007.

"Is New England Ensuring the Adequacy and Cost Effectiveness of the Region's Transmission Grid?" Panel moderator, New England Conference of Public Utility Commissioners Annual Symposium, Mystic CT, June 2007.

"Energy Regulation in Massachusetts – Concerns and Options," presentation to the Raab Restructuring Roundtable, Boston MA, June, 2007.

"View From the Regulatory Bench," comments to the New England Energy Conference and Exposition, Groton CT, May 2007.

"Energy for New England – The Demand, Supply and Price Context," presentation to Massachusetts Municipal Wholesale Electric Cooperative Annual Meeting, Boylston MA, May 2007.

"Demand Resources in New England: New Opportunities and Future Directions," Presentation at ISO-NE Annual Demand Resources Summit, Westborough MA, May 2007.

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"Carbon Cap & Trade Allocation Options – Practical Considerations," "Carbon Trading Program Emission Allowances: Practical Considerations for Allocation," and "Allocation of Carbon Allowances to Mitigate Electric Sector Costs," Reports to the National Commission on Energy Policy, May 2005.

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"Controlling China's Power Plant Emissions after Utility Restructuring: The Role of Output-Based Emission Controls" (with B.A. Finamore, N. Seidman, and T. Szymanski), *The Sinosphere Journal*, July 2002.

"Siting Power Plants in the New Electric Industry Structure: Lessons from California and Best Practices for Other States" (with S. Tierney), *The Electricity Journal*, June 2002.

"Siting Power Plants: Recent Experience in California and Best Practices in Other States" (with S. Tierney), prepared for The Hewlett Foundation and The Energy Foundation, February 2002.

"Setting and Administering Output-Based Emission Standards for the Power Sector: A Case Study of the Massachusetts Output-Based Emission Control Programs" (with N. Seidman and B. Finamore), prepared for the China Sustainable Energy Program, October 2001.

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"Output-Based Emission Control Programs – U.S. Experience" (with N. Seidman, B. Finamore, and D. Moskovitz), prepared for the China Sustainable Energy Program, May 2000.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 74
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-2 (140110,140111)

Competitively Sensitive Confidential Information

Exhibit PJH-2
Calpine LCOE Model Sources and Assumptions

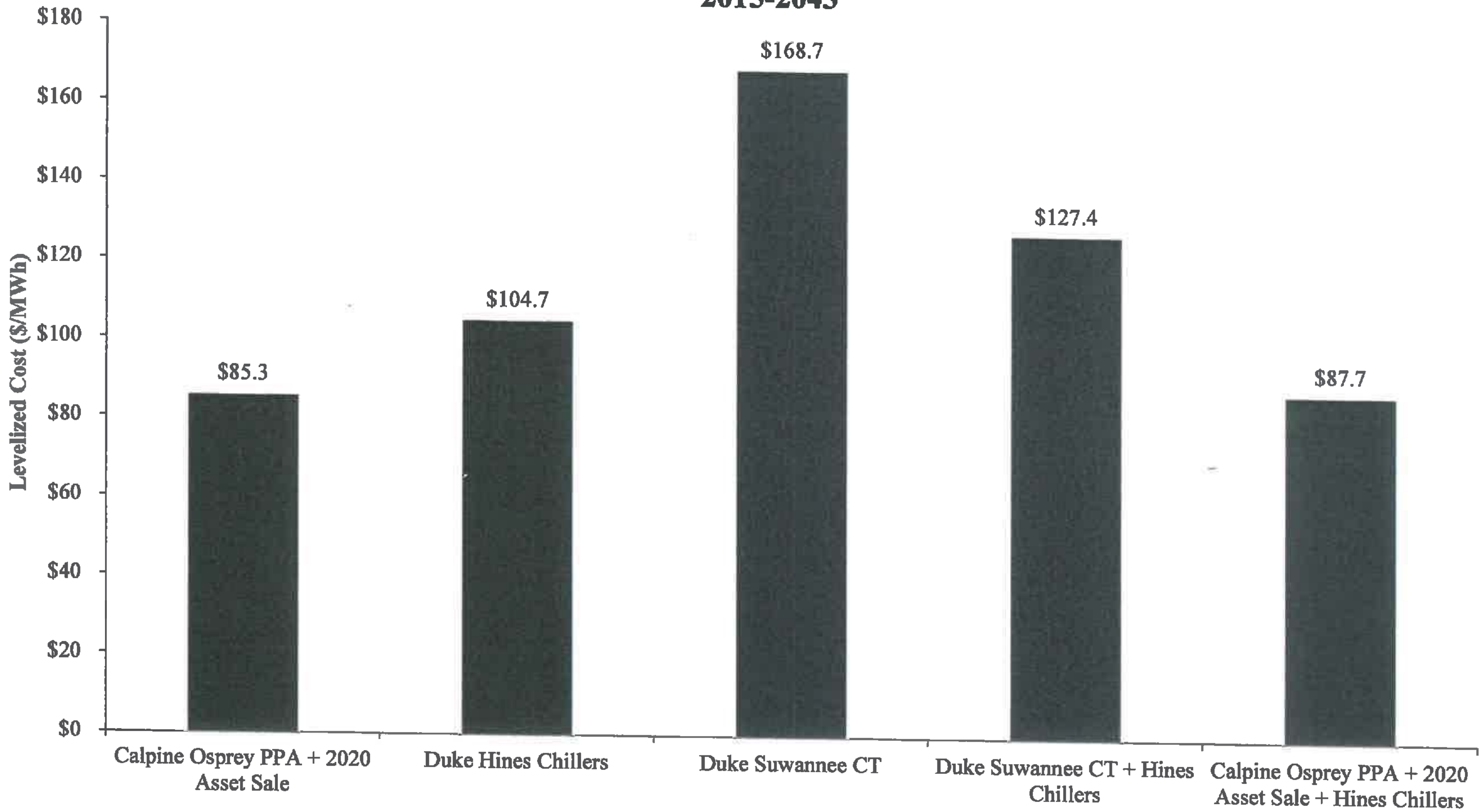
Variable	Unit(s)	Assumption	Source
Timing	Osprey	2015-2019 (PPA) 2020 - 2043 (Sale)	Calpine Bid
	Suwannee	Built 2016, 2043 End Date	
	Hines Chillers	Built 2017, 2043 End Date	Duke Proposal
Capacity	Osprey	515 MW	Calpine Bid
	Suwannee	316 MW	BMHB-2 (Summer Capacity)
	Hines Chillers	165 MW	[redacted]
Capacity Factor	Osprey	[redacted]	[redacted]
	Suwannee	9.3%	BMHB-2
	Hines Chillers	[redacted]	[redacted]
Capital Costs/ Capacity Price ($2016)	Osprey	$175 Million ($2020, Sale)	[redacted]
	Suwannee	$197 Million	
	Hines Chillers	$160 Million	Borsch Direct Testimony, Docket No 140111-EI
Heat Rate	Osprey	[redacted]	Calpine Bids (PPA) Thornton Direct Testimony, Docket No. 140111-EI (Sale)
	Suwannee	10,197 Btu/kWh	BMHB-2
	Hines Chillers	7,222 Btu/kWh	SNL Financial
Financial Assumptions	Return on Equity	10.5%	BMHB-1, p.48
	Return on Debt	3.75%	
	WACC	6.46%	
	Tax rate	35.26%	
MACRS Schedule	Osprey	20 year from IRS	IRS - Publication 946
	Suwannee	15 year from IRS	
	Hines Chillers	20 year from IRS	
Transmission Capital Costs	Osprey	$150 Million	Scott Direct Testimony, Docket No 140111-EI
Fixed O&M Costs ($)	Osprey (Sale only) Suwannee Hines Chillers	Forcasted 2015 - 2043	Strategist Input, Response to IR6
Variable O&M Costs ($)	Osprey PPA	From Bid, escalated	Calpine Bid
	Osprey Sale, Suwanne	Forcasted 2015 - 2043	Strategist Input, Response to IR6
	Hines Chillers	Forcasted 2015 - 2043	Strategist Output, IR7
Start Cost ($/start)	Osprey	[redacted]	Calpine Bid
	Suwannee	Forcasted 2015 - 2043	Strategist Output, IR7
Number of Starts	Osprey Suwannee	[redacted]	[redacted]
Natural Gas Price ($/MMBtu)	All	Forcasted 2015 - 2043	Strategist Input, Response to IR5
Gas Transportation Costs ($/ MMBtu)	Osprey	$0.55 per MMBtu	Calpine Bid
CO2 Emissions Intensity (lbs / MMBtu)	All	117.08 lbs/MMBtu	Strategist Input, Response to IR10
NOx Emissions Intensity (lbs / MMBtu)	Osprey	0.0115 lbs/MMBtu	SNL
	Suwannee	0.0106 lbs/MMBtu	DEF Response to NRG, No 27
	Hines Chillers	0.0100 lbs/MMBtu	Strategist Input, Response to IR10, Hines 2
Environmental Costs	All	Forcasted 2015 - 2043	Strategist Input, Response to IR4 and IR11

Sources:
[1] Response to Question 4, Schedule from DEF's Response to Calpine's 1st Interrogatories, Docket No. 140111, June 16, 2014, 14LGBRA-CALPINE1-4-Doc 1 Docket_140111-EI_Q4.xlsx.
[2] Response to Question 5, Corrected Schedule from DEF's Response to Calpine's 1st Interrogatories, Docket No. 140111, June 20, 2014, 14LGBRA-CALPINE1-5-DOC 1 CONFIDENTIAL Docket_140111-EI_Q5 (2).xlsx.
[3] Response to Question 6, Corrected Schedule from DEF's Response to Calpine's 1st Interrogatories, Docket No. 140111, June 20, 2014, 14LGBRA-CALPINE1-6-DOC 1 CONFIDENTIAL Docket_140111-EI_Q6.xlsx.
[4] Response to Question 7, Corrected Schedule from DEF's Response to Calpine's 1st Interrogatories, Docket No. 140111, June 20, 2014, 14LGBRA-CALPINE1-7-DOC 4 CONFIDENTIAL Docket_140111-EI-Q7- Self Build P5.xlsx.
[5] Response to Question 10, Schedule from DEF's Response to Calpine's 2nd Interrogatories, Docket No. 140111, June 24, 2014, 14LGBRA-CALPINE2-Q10b-000001 - 000004 Emission Rates 2013_0927.xlsx.
[6] Response to Question 11, Schedule from DEF's Response to Calpine's 2nd Interrogatories, Docket No. 140111, June 24, 2014, 14LGBRA-CALPINE2-Q11-000005 - 000006 Allowance Pricing 2013_0929 (2).xlsx.
[7] Direct Testimony of Benjamin M.H. Borsch, on Behalf of Duke Energy Florida, Inc., In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018. Florida Public Service Commission Docket No. 140111-EI, May 27, 2014, Exhibit BMHB-1 and 2.
[8] Direct Testimony of Edward Scott, on Behalf of Duke Energy Florida, Inc., In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018. Florida Public Service Commission Docket No. 140111-EI, May 27, 2014, Exhibit ES-3.
[9] SNL Financial.
[10] Duke Energy Florida, Inc.'s responses to NRG Florida LP's First Interrogatories Nos. 1-108 to Duke Energy Florida, Inc., No. 27.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 75
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-3 (140110,140111)

Competitively Sensitive Confidential Information

Exhibit PJH-3
Levelized Cost of Electricity ($2014/MWh)
2015-2043



Notes:
Annual average capacity factors are assumed to be [redacted] for Osprey, 9.3% for Suwannee, and [redacted] for the Hines Chillers.
[redacted]
The Osprey LCOE includes $150 in transmission costs.

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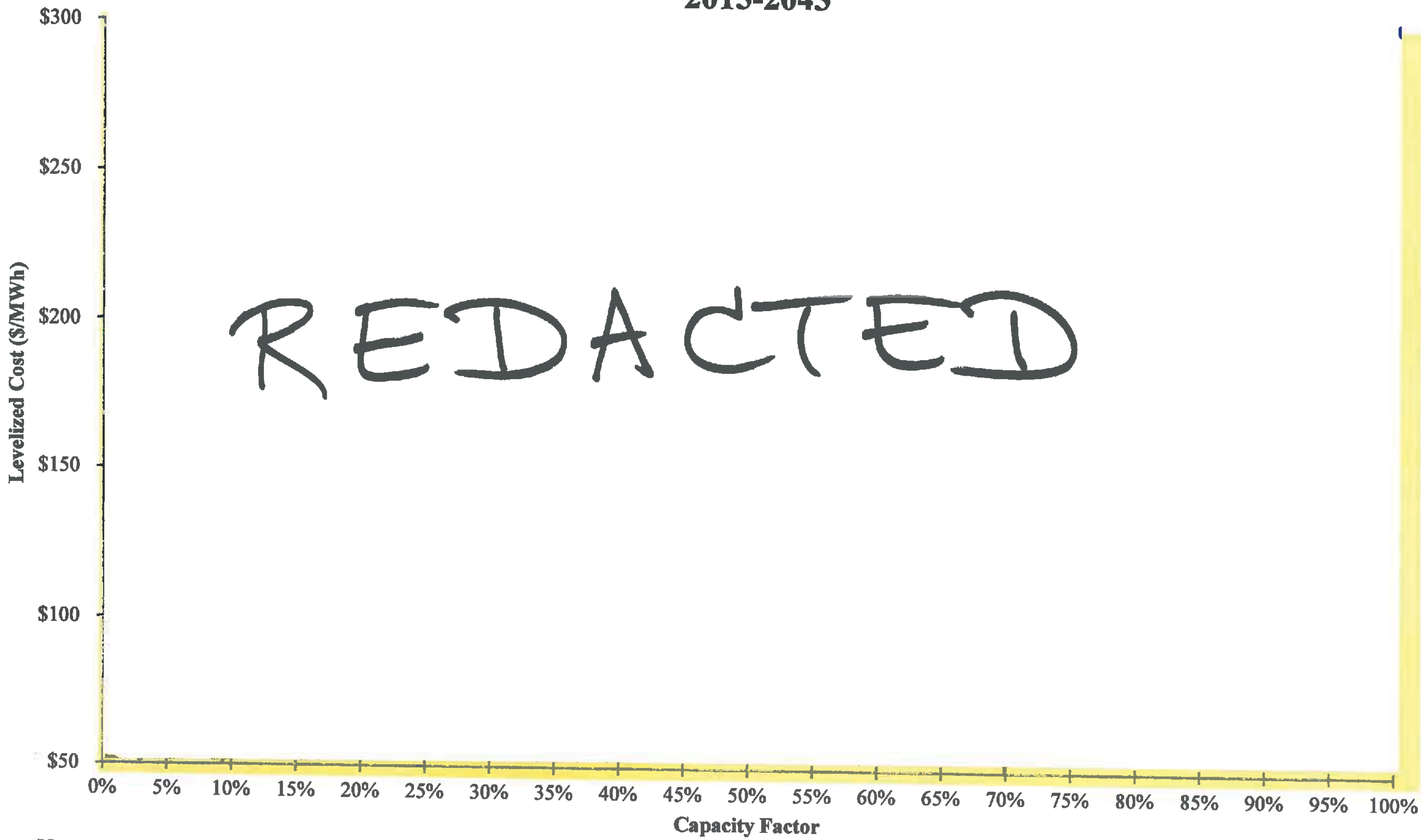
Levelized Cost of Electricity
PJH-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 76
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-4 (140110,140111)

Competitively Sensitive Confidential Information

Exhibit PJH-4
Levelized Cost ($2014/MWh) by Capacity Factor
2015-2043

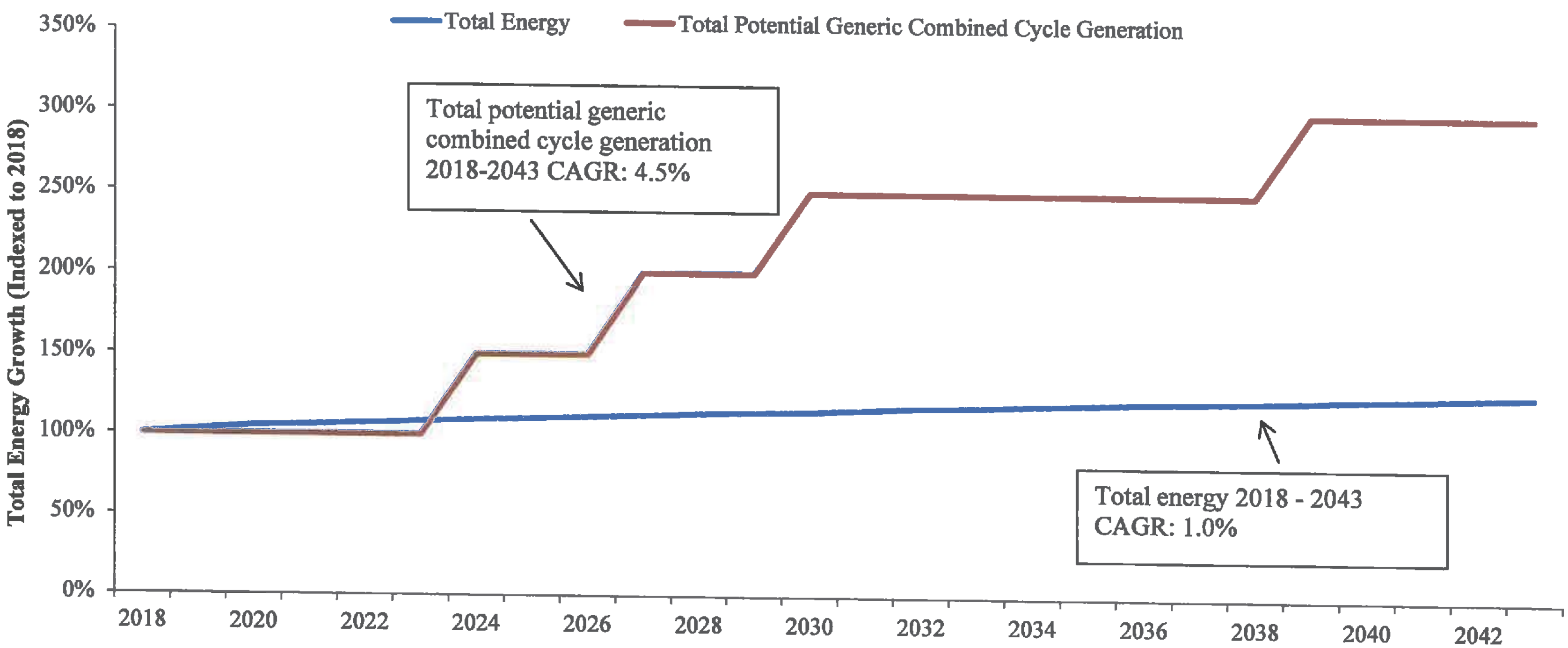


Notes:
The Osprey LCOE estimate includes a PPA starting in 2015 for 515 MW, with an acquisition in 2020 at [redacted]
The Osprey LCOE estimate includes $150 million in transmission costs.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 77
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-5 (140110,140111)

Exhibit PJH-5

Growth in Total Energy Demand and Potential Energy Generation from Generic Combined Cycle Units



Notes:
Total energy demand and potential energy generation are indexed to 2018 values.
Between 2018 and 2043, 4,758 MW of generic combined cycle capacity is added, assuming 793 MW summer capacity per unit.

Sources:
[1] Direct Testimony of Benjamin M.H. Borsch, on Behalf of Duke Energy Florida, Inc., In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018. Florida Public Service Commission Docket No. 140111-EI, May 27, 2014, Exhibit BMHB-2.
[2] Duke Energy Florida, Inc., response to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories. (Nos. 1-9), Competitively Sensitive Confidential Response 7.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 78
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-6 (140110,140111)

Competitively Sensitive Confidential Information

Exhibit PJH-6

Comparison of Osprey Capacity Factor and Starts, by Year
DEF Production Simulation Results, Scenario 5 Acquisition

Notes:
Data is from Scenario 5, Acquisition 2, modeled as -$193 m CPVRR relative to the DEF self-build proposal.
[redacted]

Source:
[1] Duke Energy Florida, Inc., Response to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories. (Nos. 1-9), Competitively Sensitive Confidential Response 6b and 7.

Docket No. 140110-EI
Comparison of Osprey Capacity Factor & Starts, by Year
PJH-6, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 79
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-7a7b (140110.111)

Competitively Sensitive Confidential Information

Exhibit PJH-7a
Adjustments to Cumulative Present Value Revenue Requirement
$2014 millions

	Original Value	Updated Value	CPVRR Impact
Duke Energy Florida Estimate			($193)
Fixed Cost Adjustment			
Updated PPA/acquistion offer	$300	[redacted]	[redacted]
Updated Estimate for Direct Connect Transmission Costs	[redacted]	$150	
Gas Reservation Charge Adjustment			
Net Adjusted CPVRR:			**$133**

Notes:
These adjustments include updates to fixed costs and other financial transactions, which are not expected to impact production cost modeling and energy dispatch outcomes.

CPVRR impact is -$193 m relative to DEF's self-build proposal. Adjustments are estimated assuming a 6.46% weighted average cost of capital with all assets fully depreciated by 2044. CPVRR adjusted impact includes estimated adjustments to rate base, depreciation, and deferred income taxes for capital expenses.
Estimate assumes a 5-year PPA for 515 MW, with capacity price payments starting at [redacted] 2015 escalating to [redacted] in 2019.

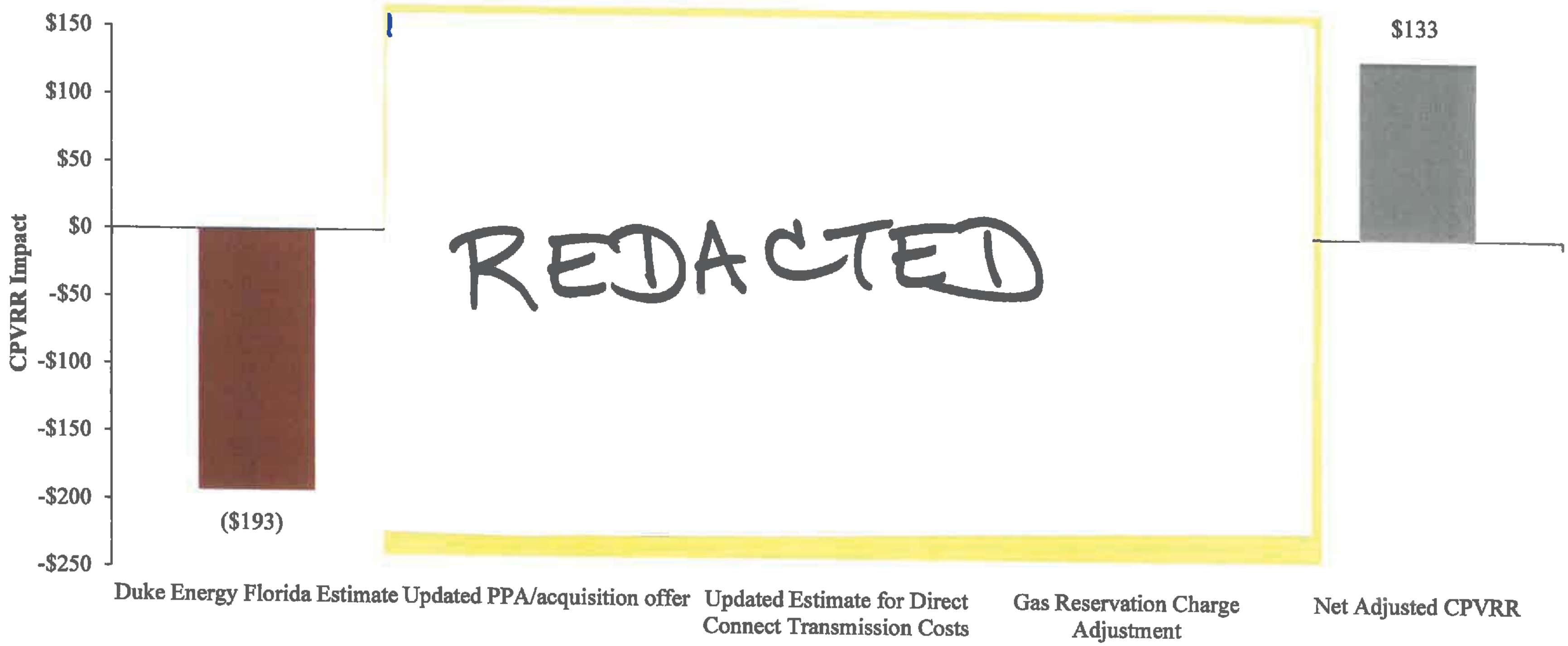
Sources:

[1] Exhibit BMHB-8, Acquisition 2.

[2] Direct Testimony of Todd Thornton, 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 July 14, 2014, at 8.

[3] Duke Energy Florida, Inc.'s Responses to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories. (Nos.1-9), Submitted June 16, 2014. Response 6a and g.

Exhibit PJH-7b
Adjustments to Cumulative Present Value Revenue Requirement
$2014 millions

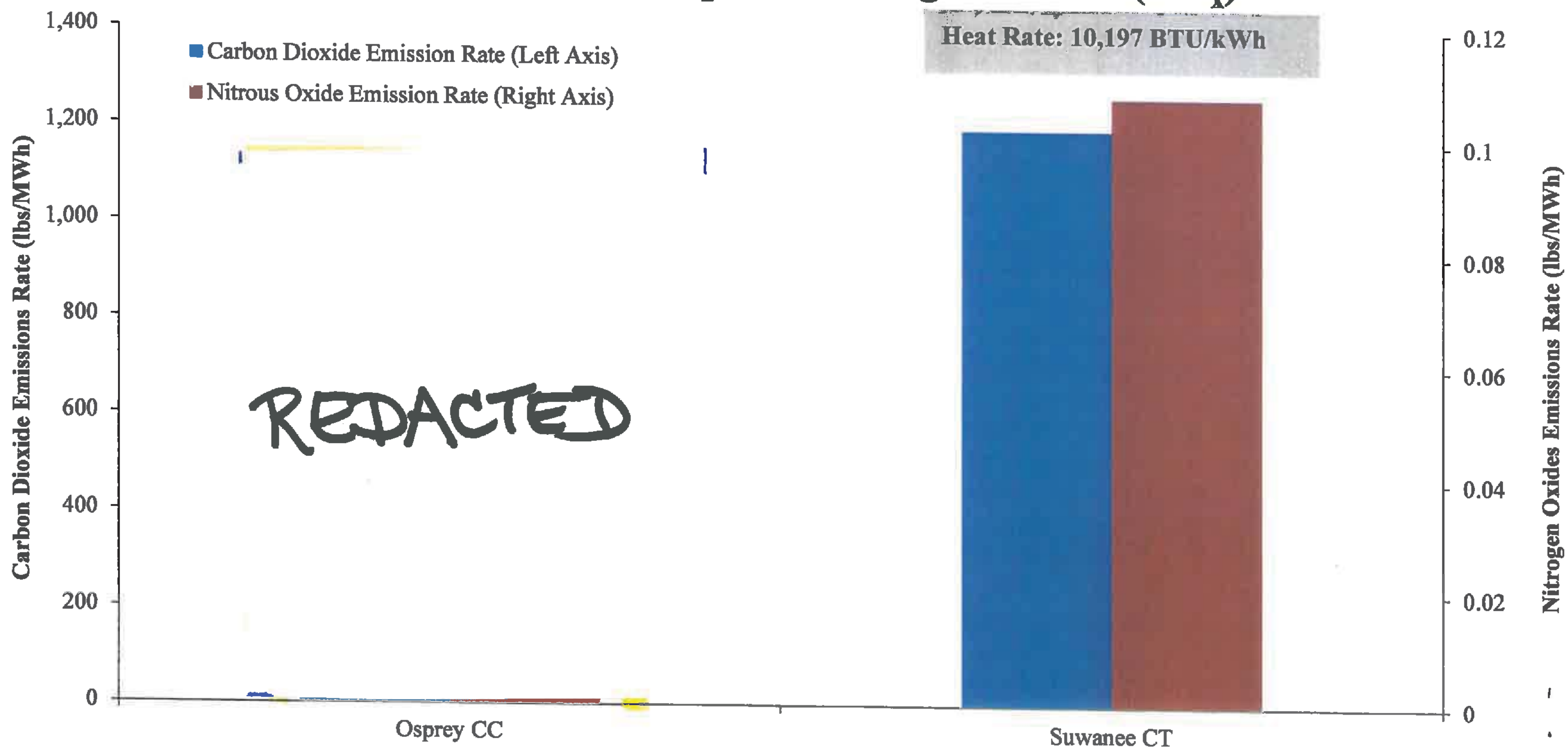


Notes:
These adjustments include updates to fixed costs and other financial transactions, which are not expected to impact production cost modeling and energy dispatch outcomes.
CPVRR impact is -$193 m relative to DEF's self-build proposal. Adjustments are estimated assuming a 6.46% weighted average cost of capital with all assets fully depreciated by 2044.
CPVRR adjusted impact includes estimated adjustments to rate base, depreciation, and deferred income taxes for capital expenses.
Estimate assumes a 5-year PPA for 515 MW, with capacity price payments starting at [redacted] 2015 escalating to [redacted] 2019.

Sources:
[1] Exhibit BMHB-8, Acquisition 2.
[2] Direct Testimony of Todd Thornton, 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 July 14, 2014, at 8.
[3] Duke Energy Florida, Inc.'s Responses to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories (Nos.1-9), Submitted June 16, 2014. Response 6a and g.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 80
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: Paul J. Hibbard PJH-8 (140110,140111)

Exhibit PJH-8
Emission Rates by Technology
Carbon Dioxide (CO_2) and Nitrogen Oxides (NO_x)



Note:
Emission rate is calculated as emission factor (lbs/MMBTU) multiplied by assumed heat rate (BTU/kWh).

Sources:
[1] Duke Energy Florida, Inc., response to Calpine Construction Finance Company, L.P.'s Second Set of Interrogatories (Nos. 110-11), 10QB. "14LGBRA-CALPINE2-Q10b-000001 - 000004 Emission Rates 2013_0927.xlsx."
[2] Duke Energy Florida, Inc.'s responses to NRG Florida LP's First Interrogatories Nos. 1-108 to Duke Energy Florida, Inc., No. 27.
[3] SNL Financial.

JOHN L. SIMPSON
40318 Colfax Road, Magnolia, TX 77354
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TRANSMISSION CONSULTANT

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

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

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

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

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

PROFESSIONAL EXPERIENCE

JOHN L. SIMPSON TRANSMISSION CONSULTING — April 2011 to Present

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

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

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

CONSULTANT — May 2007 to June 2008

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

RELIANT ENERGY, INC. — November 1999 to May 2007

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

JOHN L. SIMPSON
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John.L.Simpson@att.net

PROFESSIONAL EXPERIENCE

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

FLORIDA POWER CORPORATION — February 1985 to November 1999

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

DIRECTOR, SYSTEM PLANNING — March 1995 to November 1999

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

MANAGER, TRANSMISSION DESIGN — November 1988 to March 1995

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

MANAGER, RELAY DESIGN — August 1987 to November 1988

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

PUBLIC SERVICE COMPANY OF COLORADO — June 1972 to January 1985

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

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

EDUCATION

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

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

Registered Professional Engineer - States of Colorado and Florida

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

FPL

Ten Year Power Plant Site Plan

2013-2022

Submitted To:

Florida Public Service Commission

Miami, Florida
April 2013

Table of Contents

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

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

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

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

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

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

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

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

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

Step 4: Finalizing FPL's Current Resource Plan

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

III.B Projected Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2013 through 2022 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions that primarily consist of: (i) changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls and through other uprates to existing capacity), (ii) changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, (iii) the modernizations of FPL's existing Cape Canaveral, Riviera Beach, and Port Everglades sites by the removal of the steam generating units that were previously, or are currently, on the sites and the addition of one new, very fuel-efficient CC generating unit at each site, (iv) upgrades to the CTs at a number of existing combined cycle plants, (v) the switching of Turkey Point 1 and 2 from generation to synchronous condenser operation, and (vi) the addition of the new Turkey Point Unit 6 nuclear unit in 2022 (i.e., the year currently projected at the time this document is being finalized to be the earliest practical in-service date for this new nuclear unit).

Although the DSM additions that are consistent with the FPSC's directions regarding FPL's DSM program implementation are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The FPSC's directions regarding FPL's DSM program implementation address the years through 2019. For planning purposes in this document, FPL currently projects an additional 100 MW (Summer) of DSM per year for the subsequent three years (2020 through 2022) addressed in this Site Plan. In addition, the projected MW reductions from these DSM additions are reflected in the projected reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. (Subsequent analyses, particularly analyses that will be conducted in preparation for the 2014 DSM Goals docket, will ultimately determine the actual levels of DSM that FPL should implement in the 2015 through 2022 time frame.)

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

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

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

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 83
PARTY: CALPINE CONTRUCTION FINANCE COMPANY, L.P. – (DIRECT)
DESCRIPTION: David Hunger, Ph.D. DH-1 (140111-EI)

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
130905	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
130906	PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
130903	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI
EXHIBIT: 84
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: Jeffry Pollock JP-1 (140110, 140111)

J.POLLOCK
INCORPORATED

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebutal	IA	Class Cost-of-Service Study	10/1/2013
130902	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
130203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
130201	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
121203	JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Excemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
121001	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings	4/30/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013

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121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
120502	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
120101	LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
91023	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
110703	GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011

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90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010

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100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009

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80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008

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80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study; revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007

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61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007
61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007
41219	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	08/23/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006

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50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004

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8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004
8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002
7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001
7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999
7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

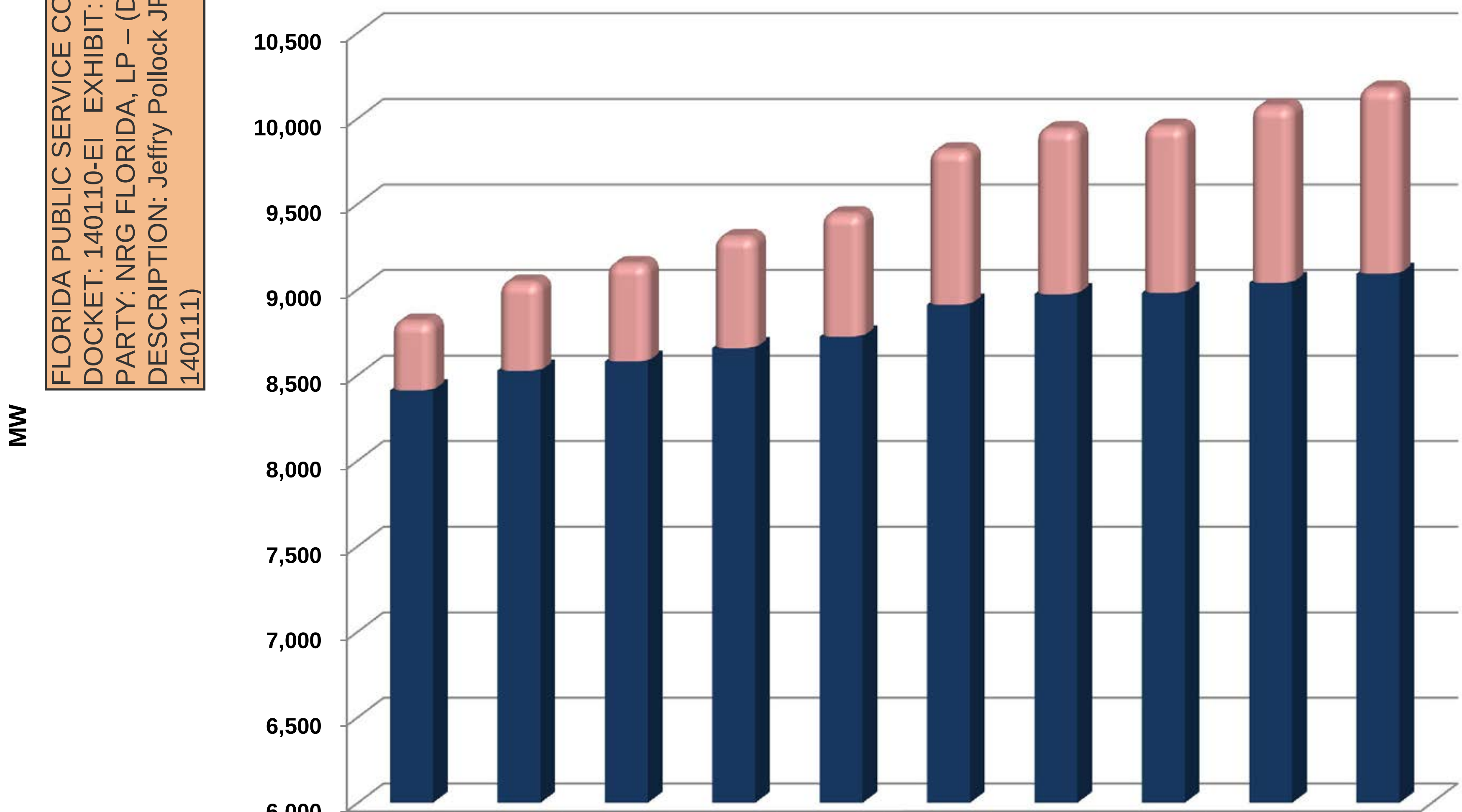
PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/21/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 85
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: Jeffry Pollock JP-2 (140110, 140111)

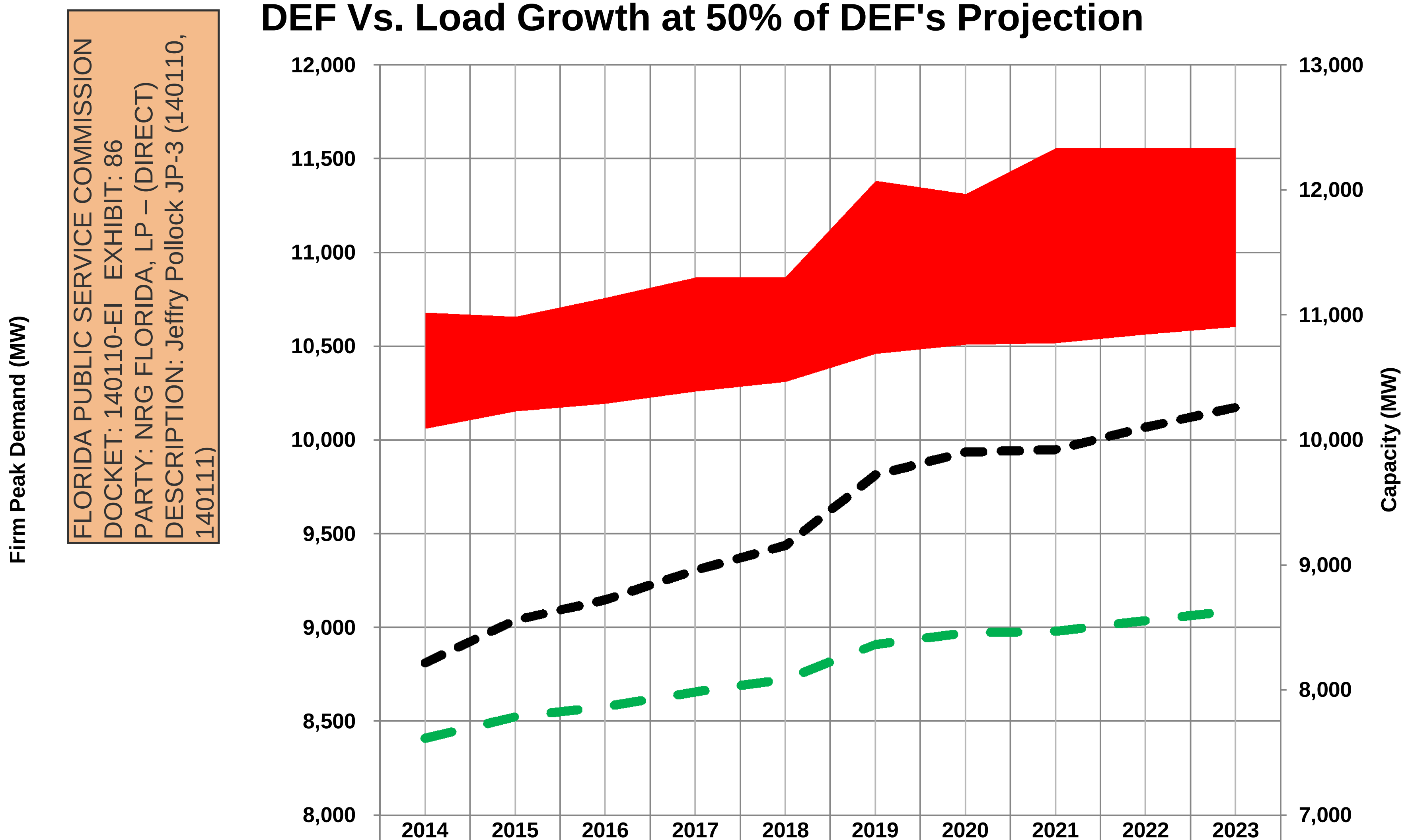
DUKE ENERGY FLORIDA
Projected Net Firm Summer Peak Demand
Projected 2014-2023



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
DEF Additional Load Growth	402	516	570	649	716	902	964	971	1,030	1,083
At 50% of Projected Growth	8,411	8,525	8,579	8,658	8,725	8,911	8,973	8,980	9,039	9,092

Source: Duke Energy Florida 2014 Ten Year Site Plan

Projected Summer Capacity and Firm Peak Demand
DEF Vs. Load Growth at 50% of DEF's Projection



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Potential Excess Capacity	930	760	844	915	837	1,383	1,204	1,563	1,493	1,429
At 50% of Projected Growth	10,093	10,230	10,295	10,389	10,469	10,693	10,767	10,776	10,846	10,910
DEF Proj. Firm Peak Demand	8,812	9,041	9,149	9,306	9,440	9,813	9,936	9,951	10,068	10,174
At 50% of Projected Growth	8,411	8,525	8,579	8,658	8,725	8,911	8,973	8,980	9,039	9,092

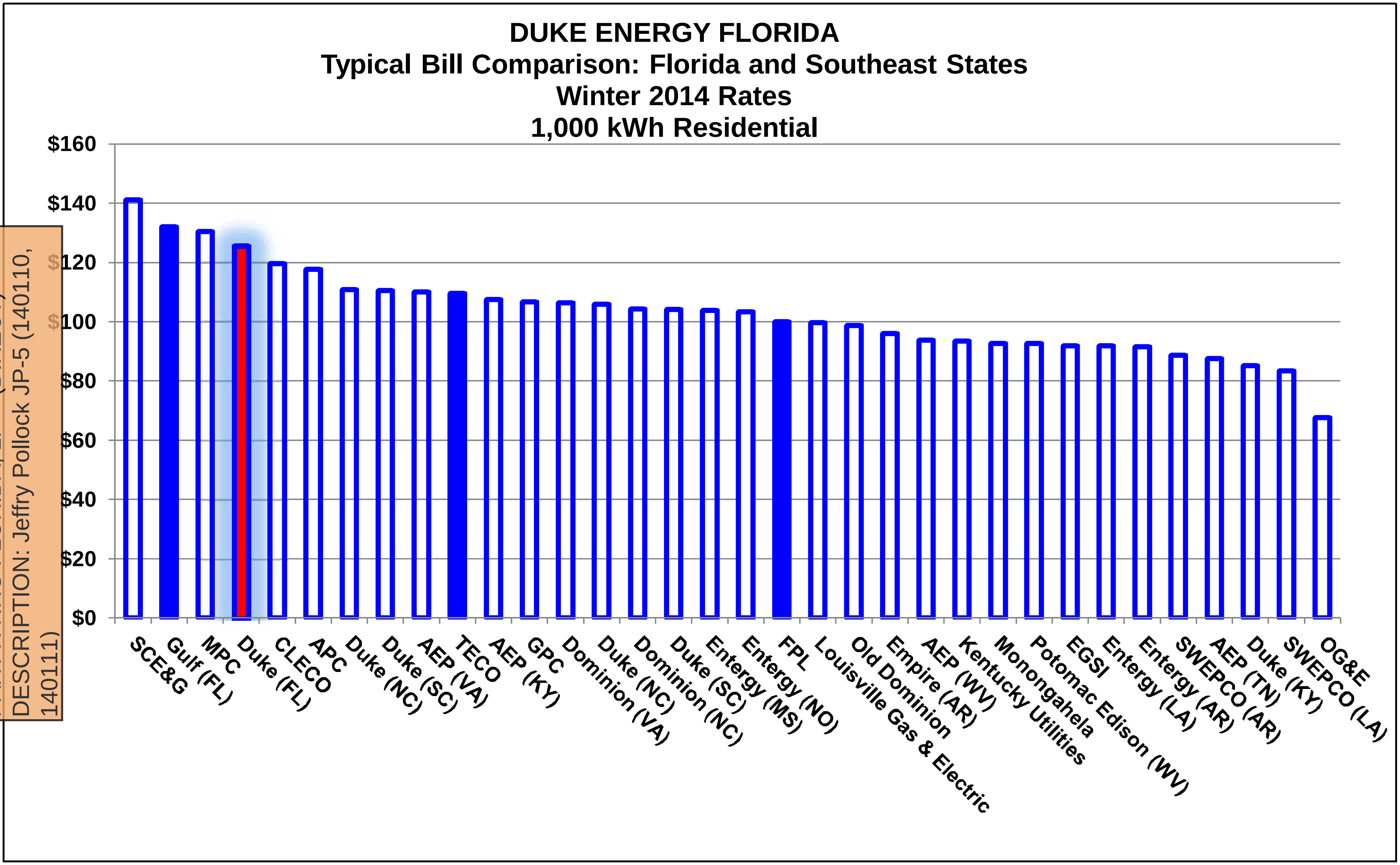
DUKE ENERGY FLORIDA
Scheduled Rate Increases Associated With Future Capital Recovery
Pursuant To The 2013 Settlement
(Dollar Amounts in Millions)

Line	Description	Effective Date	Capital Recovery	Pargraph in D.130208 Settlement	Notes	Source of Cost Data
		(1)	(2)	(3)	(4)	(5)
	Existing Generation Facilities					
1	Point of Discharge Cooling Towers	Jan-13	$18.2	9b	3-Year Amortization	d.
2	Base Rate Increase	Jan-13		13	$150 Million per Year	b.
3	Levy EPC Contract Cancelation	2013-2017	$350.0	11	5-Year Amortization	b.
4	Crystal River 3 EPU	2013-2019	$323.0	9a	7-Year Amortization	a.
5	Fuel Factor Increases	Jan-14		7	$1.00 /MWh: 2014-2015 $1.50 /MWh: 2016	b.
6	Crystal River 3 Regulatory Asset (RA)	Jan-17	$1,466.0	5e2	Capped Amount; 20-Year Recovery	b.
7	Crystal River 3 Dry Cask Storage	Jan-17	TBD	5e1	Recovery Commences After CR3 RA	
8	CR3 Nuclear Decommissioning Trust	As Needed		7b	Up to $8 Million/Year	
9	Crystal River South	Jan-21	TBD	8	Remaining Book Value	
10	Total		$2,157.2			
	New Generation Facilities					
11	Suwannee Simple Cycle Project	Jun-16	$197.0	16a	Limited Proceeding; 35-Years	c.
12	Hines Chiller Uprate Project	Mar-17	$160.0	16a	Limited Proceeding; 29 Years	c.
13	Citrus County Combined Cycle	May-18	$1,514.0	16b	GBRA	c.
14	Total		$1,871.0			
15	**Total Future Capital Recovery**		**$4,028.2**			

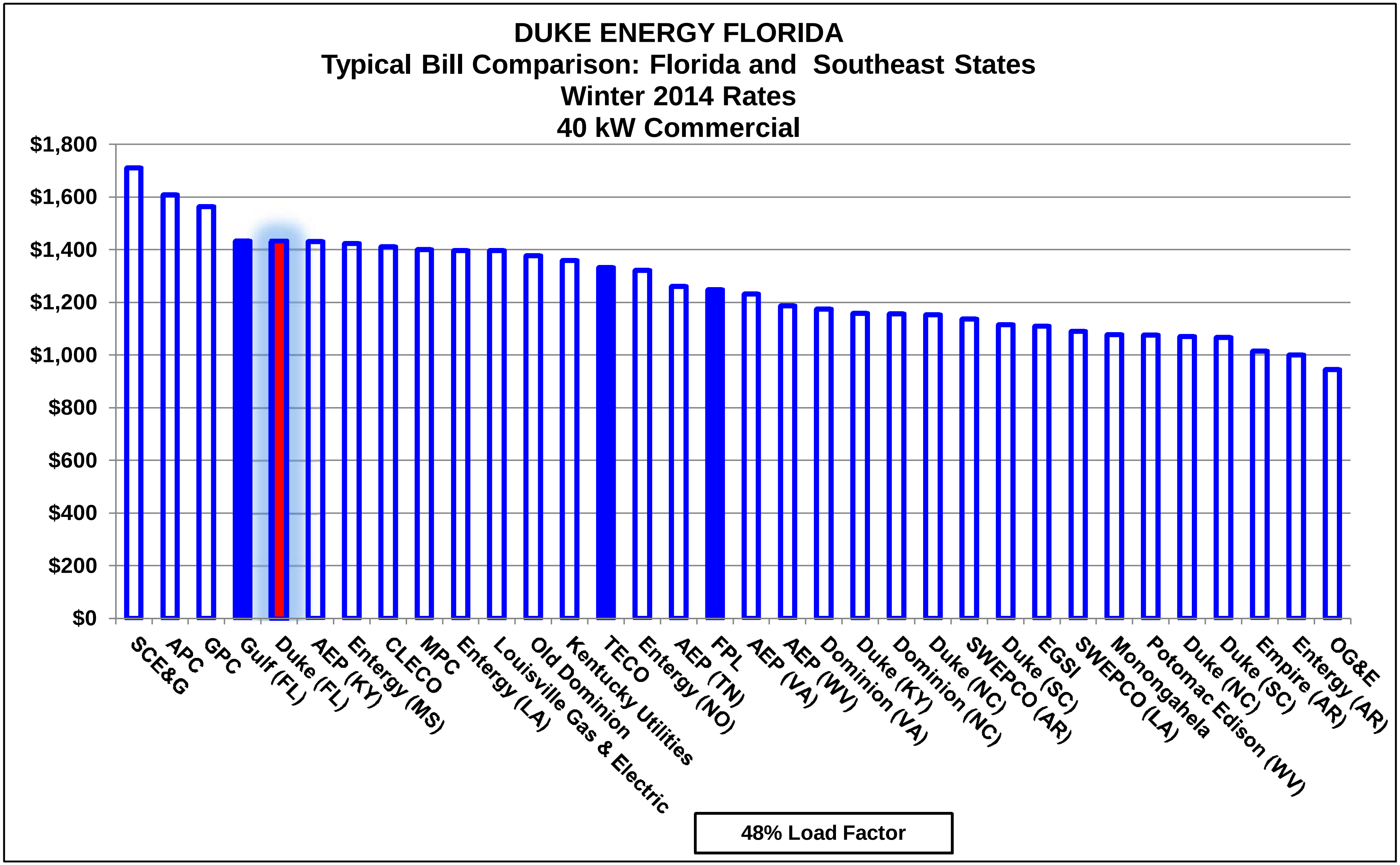
Sources:
a 2013 FERC Form 1 Report.
b Settlement in Docket No. 130208.
c DEF Petitions in Docket Nos. 140010 and 140011.
d. Direct Testimony of Thomas G. Foster, Docket No. 130007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 87
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: Jeffry Pollock JP-4 (140110, 140111)

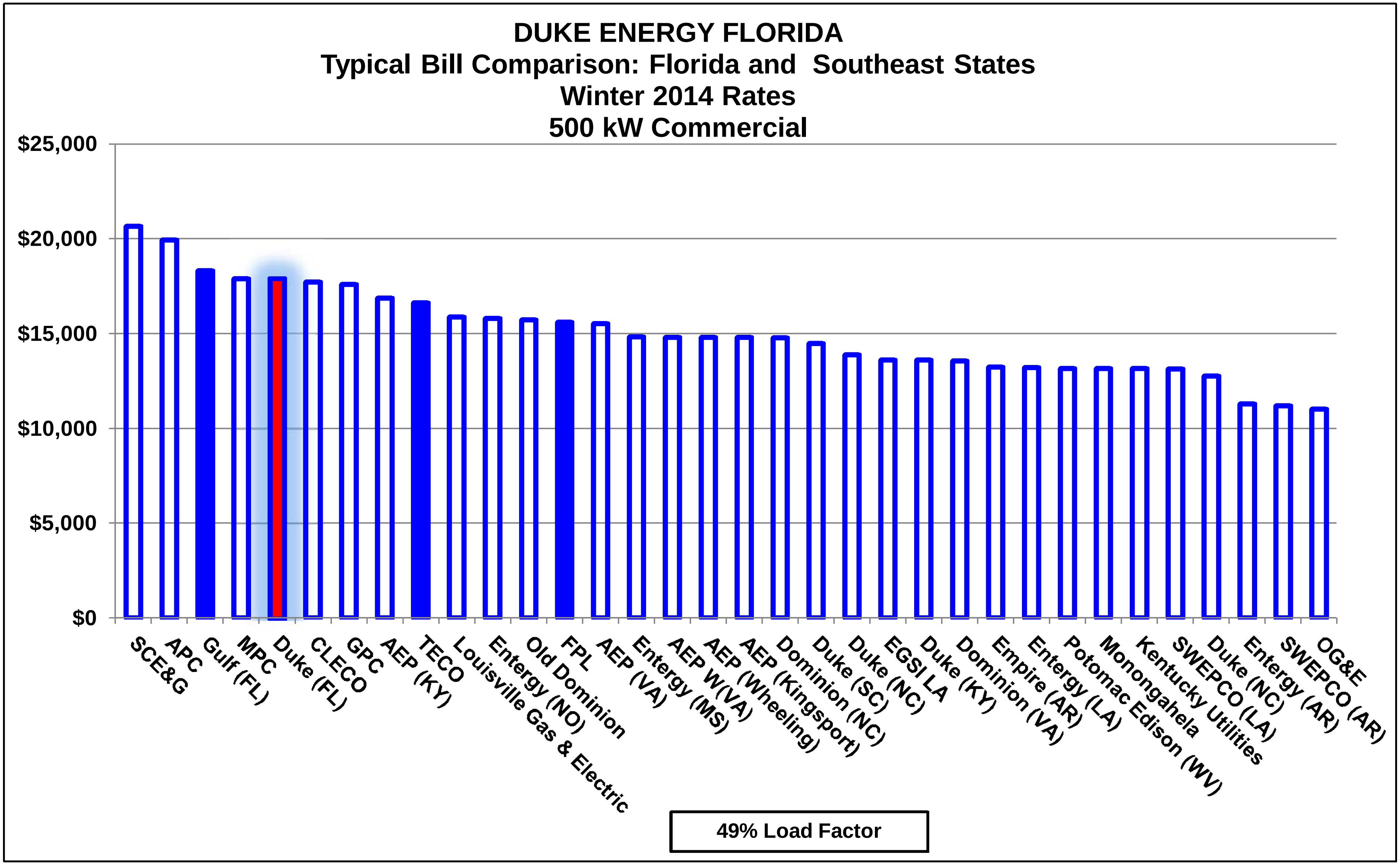
Docket No. 140111-EI
Bill Comparison - Winter 2014
Exhibit JP-5, Page 1 of 4



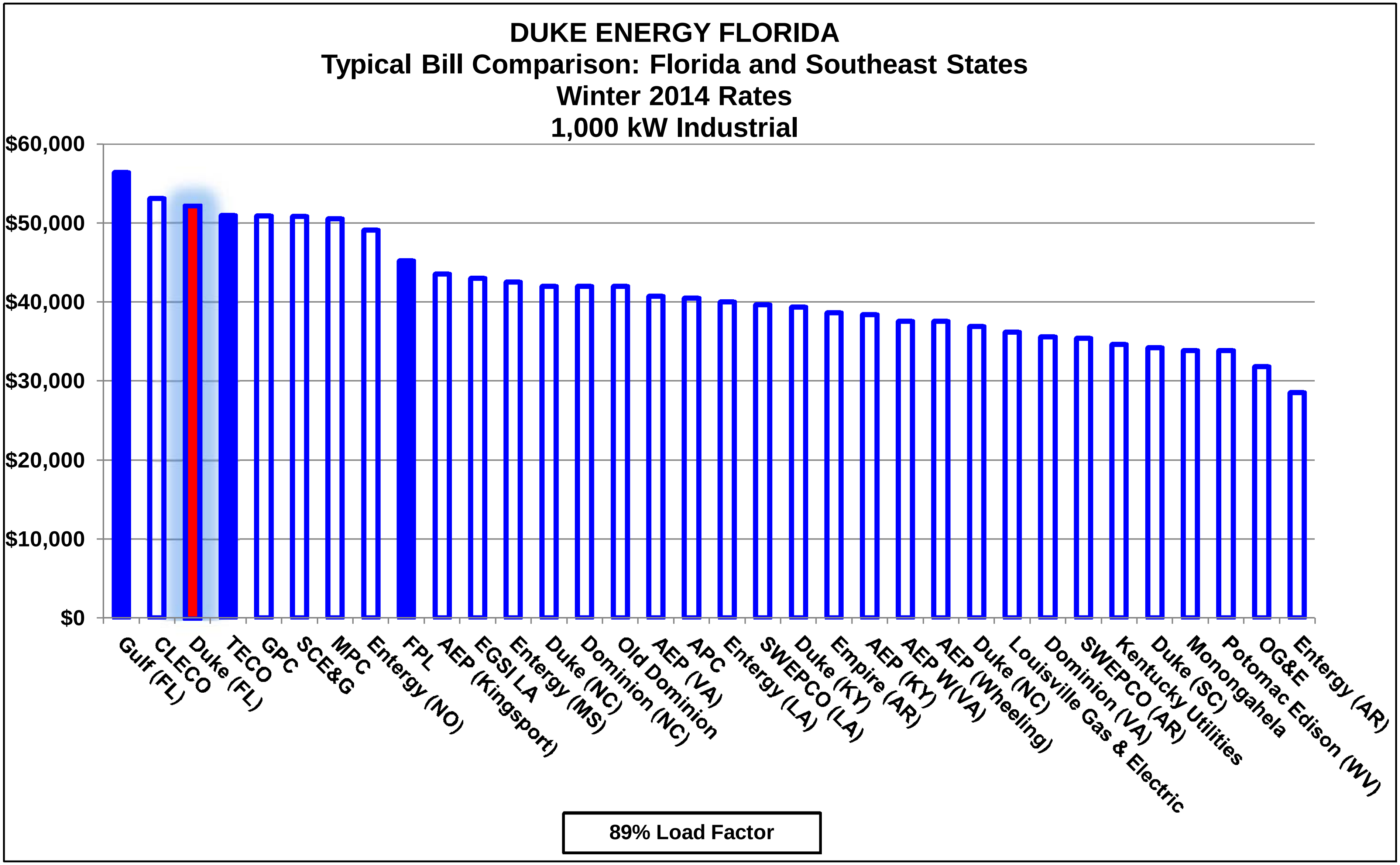
Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014

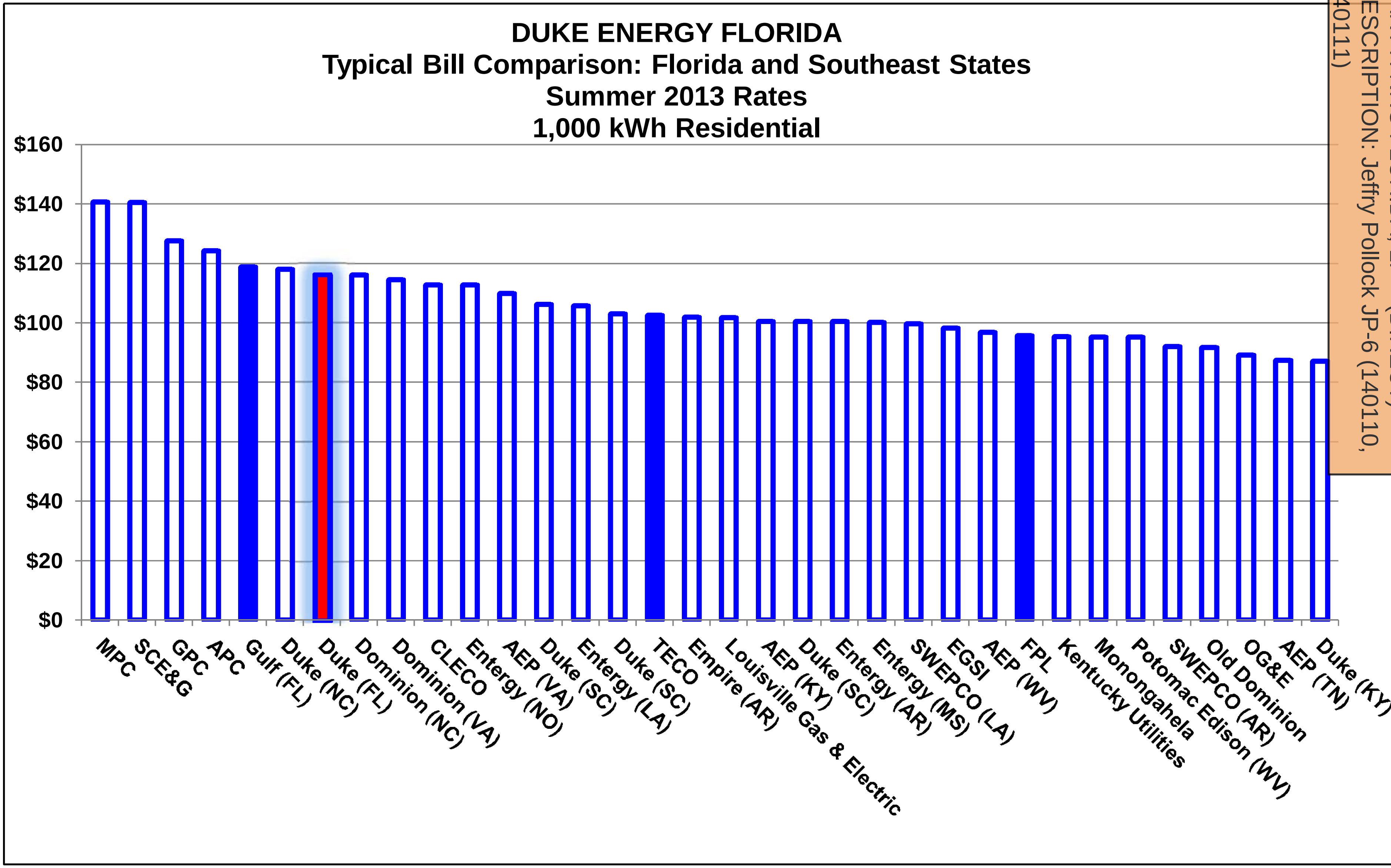


Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014

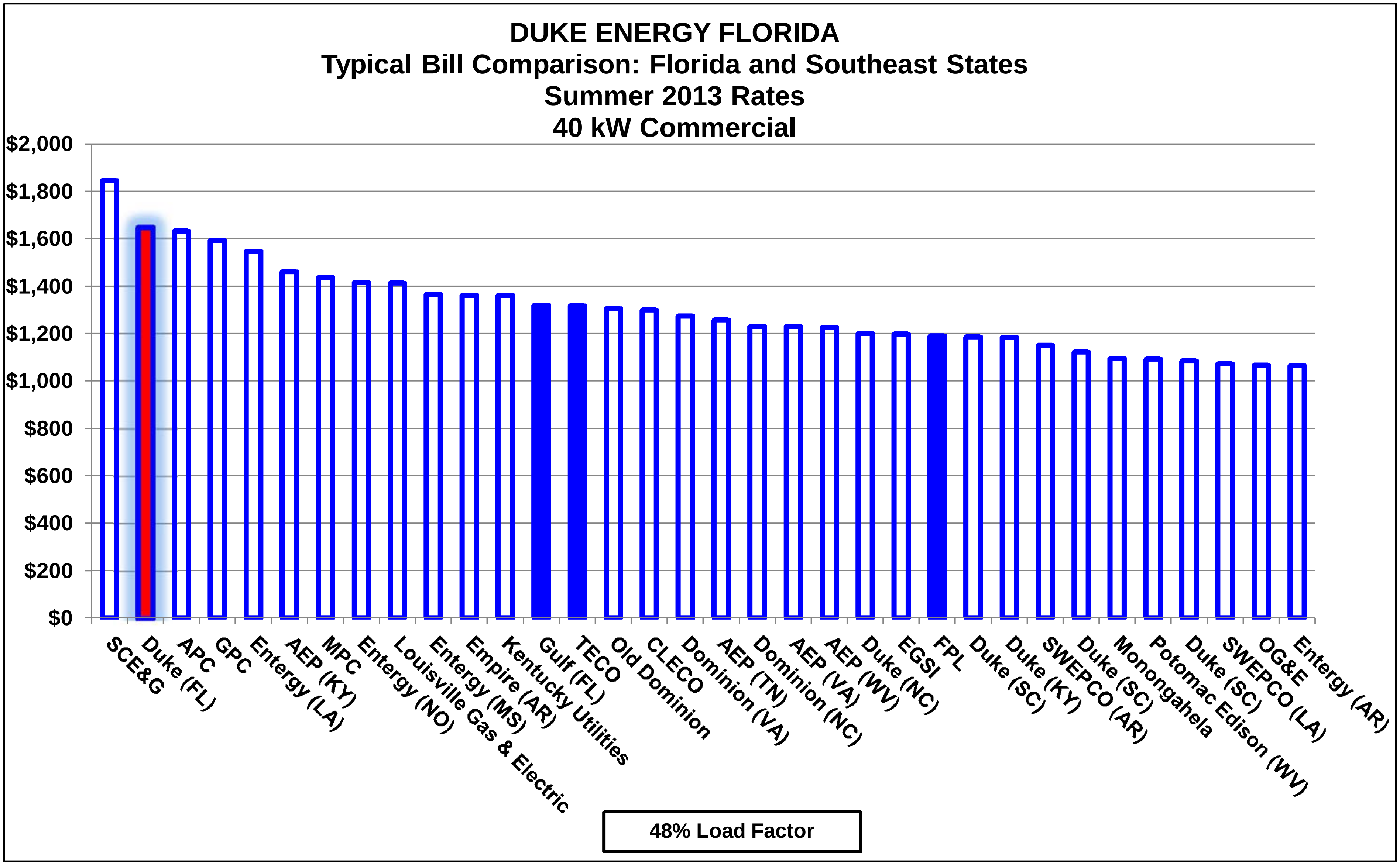


Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014

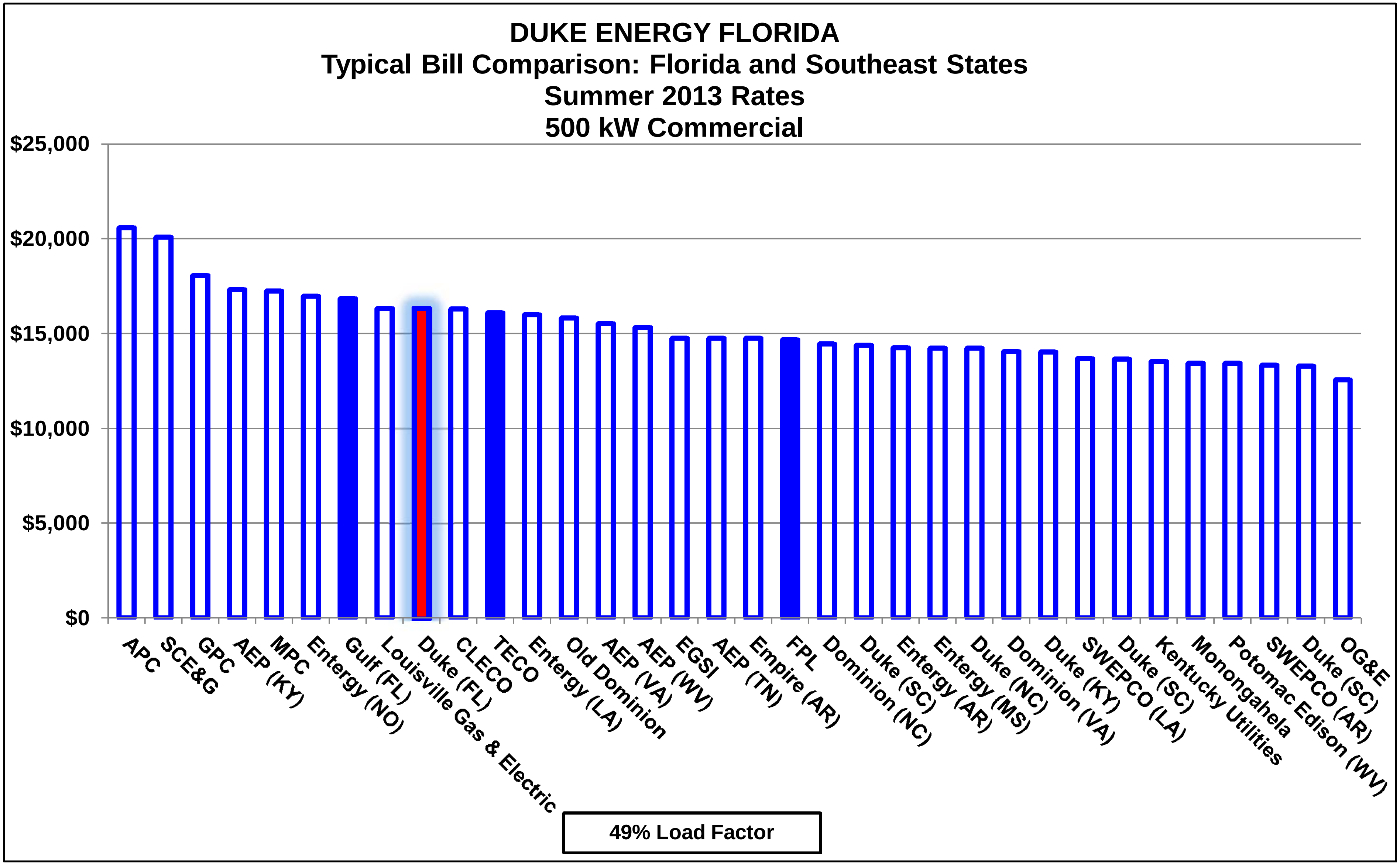
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 89
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: Jeffry Pollock JP-6 (140110, 140111)



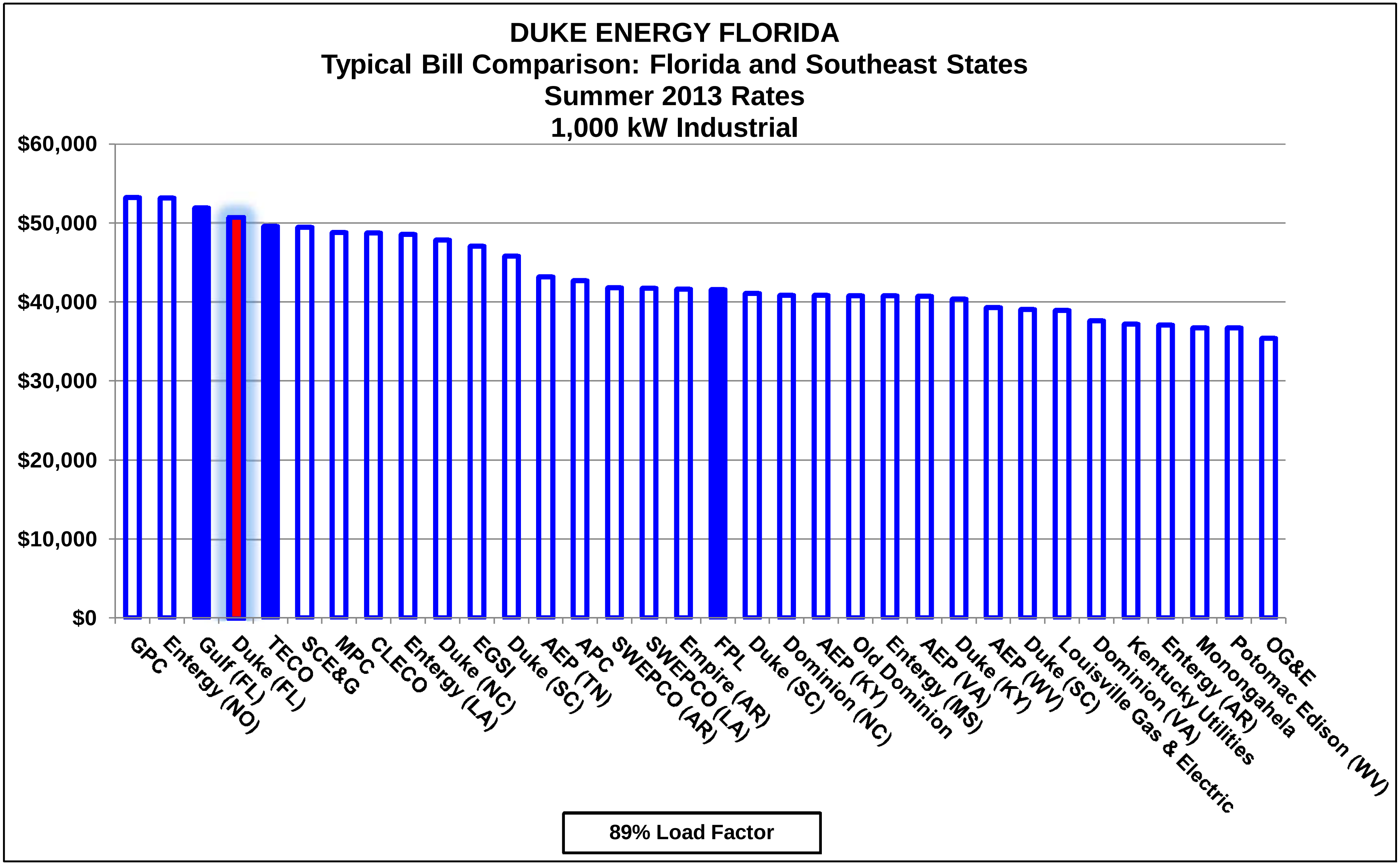
Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Summer 2013



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Summer 2013



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Summer 2013



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Summer 2013

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 90
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: John F. Morris
JRM-1(140110,140111)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 91
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: John F. Morris
JRM-2(140110,140111)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 92
PARTY: NRG FLORIDA, LP – (DIRECT)
DESCRIPTION: John F. Morris
JRM-3(140110,140111)

93

DEF's responses to Staff's First Set of Interrogatories, Nos. 1-43

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 93
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's First Set of Interrogatories, Nos. 1-43. See also files contained on S...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI DATED: JULY 15, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-43)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-43) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-43), served on July 7, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

The following questions refer to the direct testimony of Benjamin M.H. Borsch.

1. On page 20, the witness states that "The Company plans to retire CR1 and CR2 in 2018."

   a. Why is DEF planning to retire CR1 and CR2 in 2018 as opposed to 2020?

      RESPONSE: Please see DEF's response to Citizens' First Set of Interrogatories, Number 3.

   b. If DEF continued operating CR1 and CR2 through 2020, could the reliability need for the proposed Citrus County Combined Cycle power plant be deferred until 2020?

      RESPONSE: Please see DEF's response to Citizens' First Set of Interrogatories, Number 3.

c. What, if any, additional costs or savings will result from a decision to close CR1 and CR2 in 2018 as opposed to 2020?

<u>RESPONSE</u>: Please see DEF's response to Citizens' First Set of Interrogatories, Number 3.

2. Referring to page 20, lines 16-23 and page 21, lines 1-2, when did the planned retirement of the discussed combustion turbine generation plants first appear in the Company's Ten-Year Site Plan?

<u>RESPONSE</u>:

The planned retirement of Avon Park, Rio Pinar and Turner P1&P2 first appeared in the 2008 Ten Year Site Plan.

3. Referring to page 22, lines 13-15, please describe in detail what led to the increased capacity of the 2018 combined cycle power plant?

RESPONSE:

In the 2013 TYSP, DEF included a 3x1 combined cycle (1,189 MW) unit entering service in June 2018 and a 3x1 combined cycle (1,189 MW) unit entering service in June 2020 in the recommended plan to meet the Company's needs identified in the planning process. At that time, it was evident that a request for proposals and bid evaluations process would be undertaken later in 2013 if the need for combined cycle generation in 2018 was confirmed. Subsequent to issuing the 2013 TYSP, DEF's planning team continued to perform additional detailed studies, working with Company experts examining configuration and timing options for the needs over this planning period, and using the most current and detailed information available to evaluate, establish and select the most cost effective generating option to be proposed as the next planned generating unit, or NPGU, in the request for proposals that was ultimately issued in September 2013.

The 4x2 configuration, while larger than the 3x1 configuration, is supported by the Company's needs during this time period, offers DEF many benefits, including the ability to capture the cost savings and efficiencies of shared common facilities and integrated construction sequencing. It allows the Company to connect the power blocks in a grid configuration that supports both the 230kV and 500kV systems in a manner similar to the generation it is replacing and leveraging much of the existing infrastructure. This configuration also offers the reliability benefits of using two steam turbine generators to provide greater component diversity and to reduce the N-1 contingency for the facility.

Considering all of the information available, the planning team confirmed the reliability and economic need for new combined cycle generation in 2018 and beyond, and determined that the 4x2 combined cycle configuration would be the best approach to meet DEF's needs, considering cost effectiveness, system operations and reliability. The 4x2 configuration became the NPGU for the RFP, was proposed by DEF in response to the RFP and was subsequently included in DEF's 2014 TYSP.

4. On page 23, the witness states that "DEF also examined alternative generation expansion scenarios when it identified the need for additional generation capacity in 2018 in its IRP process."

a. Did DEF evaluate the conversion of the CR1 and CR2 boilers to fire natural gas?

RESPONSE:

Yes.

b. If no, why not?

RESPONSE:

Not applicable.

c. If yes, please discuss the results of DEF's evaluation.

RESPONSE:

DEF did consider conversion of the CR1 and CR2 boilers to fire natural gas in the course of its early screening evaluations of MATS compliance options, along with the assessment of MATS compliance coal scenarios. The evaluations considered the estimated costs for the boiler conversions and the cost of the gas laterals and M&R facilities as well as the projected performance impacts (efficiency, capacity) of the conversions. The evaluation also considered additional potential costs and safety issues related to the proximity of the units and the gas lateral to the fuel storage and control room facilities at Crystal River 3.

In the early phase of screening when this analysis was performed, a plan featuring alternate coal for limited extended operation from 2015-18 was compared with plans to convert CR 1&2 and operate on natural gas from 2015-18 and from 2015-2025. The economic results of the screening study showed the alternate coal option to be roughly $200M to $300M favorable compared with the natural gas options, so the natural gas options were not explored further.

5. On page 23, the witness states that "Generation alternatives that passed the initial screening were considered viable generation capacity alternatives and were included in the next step of the IRP process." Please provide a list of the generation alternatives that passed the initial screening. Please include in this list the generating capacity of each alternative.

RESPONSE:

This is list of the Generation Alternatives that passed the initial screening and were included in the next step of the IRP process:

Alternative	Summer Total Capacity (MW)	Winter Total Capacity (MW)
Combustion Turbine	187	214
Combined Cycle 2x1 G	793	866
Combined Cycle 3x1 G	1189	1307

6. On page 29, lines 14-17, the witness states "based on the Company's prior experience implementing its dispatchable demand-side resources, such resources cannot be used as often or as long as physical generation reserves without eventually affecting customer participation levels in the dispatchable DSM programs." Please describe in detail the Company's experience as it is described in this statement.

RESPONSE:

Over the years in which DEF has administered dispatchable demand-side resources, DEF has seen several instances in which customers have left such programs in large numbers. First, in several summers in which Florida has experienced unusually high temperatures, DEF has had to move beyond interrupting customer pool pumps and hot water heaters and has had to use interruptions to customer air conditioners. While this is generally an uncommon occurrence for long durations, customers have reacted very negatively to extended air conditioner interruptions and have left these dispatchable programs in large numbers during these periods. Additionally, between 2006 and 2012, Florida had instances of extreme cold weather events which led to DEF having to interrupt electrical heating service for customers including several school systems. During these times, students at schools were sent home and media coverage resulted from the events. This led to some of the impacted school systems withdrawing from such interruptible programs. These examples demonstrate the logical concept that customers will have little tolerance for extended interruptions to cooling and heating services in times of extreme weather, which, of course, are the times in which DEF will need generation reserves the most.

7. On page 29, lines 17-19, the witness states that "customers are less willing to accept service under the dispatchable DSM demand-side resource programs for lower rates when interruptions in electric service increase in frequency or duration." Please provide any evidence the company relied on in support of this statement. Please provide an example supporting this statement.

<u>RESPONSE</u>:

Please see DEF's response to Staff's Interrogatory 6.

8. On page 30, lines 2-3, the witness states that "DEF believes this [a 60 percent physical reserve of total summer reserve capacity] is an appropriate level of physical reserves." Has DEF performed any studies evaluating the need for a generation only reserve margin? What documentation or other evidence has DEF relied on to reach this conclusion?

RESPONSE:

DEF has experience with non-firm resources (e.g. load control, interruptible loads) and has historically included these resources in its planning process. DEF has not performed studies to establish a specific level of physical reserves required. During summer months when higher loads occur over sustained periods, it has been the Company's experience that generation reserves are preferred to support system reliability, and that the projected level of reserves achieved with the addition of the Citrus Combined Cycle Power Plan is reasonable and prudent.

In addition, please see DEF's response to Staff's Interrogatory 6.

9. Please refer to page 30, lines 9-22 and page 31, lines 1-10, for the following questions.

   a. Please provide a projected timeline, including critical milestones, to construct a new utility-scale coal fired power plant.

RESPONSE:

DEF does not have this information and notes that such timelines and milestones would be dependent on several factors such as the location and type of plant constructed. However, DEF estimates that a modern, utility-scale coal plant would generally take at least 6-7 years to construct.

   b. Please provide a projected timeline, including critical milestones, to construct a new nuclear generation.

RESPONSE:

DEF does not have this information and notes that such timelines and milestones would be dependent on several factors such as the location and type of plant constructed. However, DEF estimates that DEF's prior Levy construction schedule is instructive and that new nuclear generation construction would take at least ten years to construct.

10. On page 36, the witness states that "renewable resources such as wind, solar, and bio-mass are not commercially available on a utility-scale for generation capacity at a cost-effective price." For planning purposes does DEF consider wind or solar capacity a firm resource? Please explain your answer.

RESPONSE:

For planning purposes, DEF does not consider wind and solar (with no back-up or storage capability) a firm resource.

Intermittent and variable resources such as wind and solar technologies produce energy on an as-available, minute by minute basis. There is no certainty as to the quantity, timing or reliability of their energy deliveries to the grid. These intermittent and variable resources do not have normally continuous and consistent fuel supplies, therefore they do not have the capability to deliver predefined energy amounts to the grid on a dependable, continuous or consistent (minute-by-minute) basis, 24/7. From a planning reliability standpoint, they cannot be considered a regularly available generating resource when assessing the adequacy of resources available to DEF to reliably serve its firm load obligations around the clock. Unlike a firm resource, the utility cannot rely on intermittent and variable resources to contribute to energy reserves or to support system reliability. For example, solar PV generation has essentially no fuel source available at the expected time of DEF's annual peak and cannot be counted as having dependable peak-hour capability to contribute to DEF's planned energy reserve margin. And finally, intermittent and variable resources that produce energy, which varies on a minute-by-minute basis cannot be relied upon to support reliability standards, including operating reserves or address system disturbances that may occur at any moment of the day or night.

11. On page 36, the witness states that "DEF has held open a Request for Renewables ("RFR") for renewable generation resources for years." When did DEF first issue its RFR? Has any party responded to the RFR? If so, please describe the outcome of each response.

RESPONSE:

Duke Energy Florida first issued its RFR on July 19, 2007. The attached spreadsheet reflects parties that have responded and the Company's notes about outcomes. While this list represents most inquiries from Renewable developers, there may be some minor margin of error associated with capturing every single inquiry for the past seven years.

Please see the attached "Inquiries 2007_2014" spreadsheet bearing Bates numbers 14BGBRA-STAFFROG1-11-DOC 1. This document is confidential and subject to DEF's Sixth Notice of Intent filed contemporaneously with the service of this response.

12. On page 37, the witness states that "the Citrus County Combined Cycle Power Plant will displace generation from other less efficient and less well controlled sources." Please identify the sources referred to in this statement.

RESPONSE:

Citrus County Combined Cycle Power Plant will displace generation from other less efficient and less well controlled sources such as the coal units at Crystal River, the Anclote steam units and the peakers.

13. Please complete the table below summarizing the revenue requirements for each transmission plan scenario as listed in Exhibit No. BMHB-13. Please provide this information for the Reference Case, High Gas Price Case, and No CO2 Price Case. Please provide this information in electronic format (excel).

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
2032								
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2038								
2039								
2040								
2041								
2042								
2043								
2044								
2045								
2046								
2047								
2048								
2049								
2050								
2051								

2052								
2053								
Total								

<u>RESPONSE</u>:

Please see chart attached in Bates range 14BGBRA-STAFFROG1-13-DOC1. Please also see DEF's response to OPC's First Request for Production of Documents #9.

14. Referring to page 78, lines 17 – 21, of the testimony:

a. Please provide DEF's carbon cost forecasts used in the instant need determination case in dollars per ton ($/ton) for the forecast period, 2014 through 2040, expressed in 2014 dollars.

RESPONSE:

Please see DEF's response to Calpine's First Set of Interrogatories Number 4.

b. Please identify all the assumptions and evidence DEF used in developing its carbon cost forecasts.

RESPONSE:

The following is the set of specific assumptions that helped guide the development of our CO_2 price forecast. In addition, please refer to DEF's response to question 14c for a discussion of the analysis that lead to our current CO_2 price forecast.

- **EPA is in the early stages of developing a CO_2 regulation for existing fossil-fueled electric generating units. It is not known whether the regulation will establish a price on CO_2 emissions.**
- **While the economy has improved, the main focus of Congress and the White House for the next few years will be on taking actions to create jobs, lower the national debt, and restructure entitlement programs. There will be no successful legislative efforts to enact any federal greenhouse gas regulatory program during this period.**
- **Florida will not move on its own to establish greenhouse gas regulatory programs that establish a price on CO_2 emissions.**
- **Despite the lack of focus on climate change among federal policymakers, the issue will continue to be a major focus of environmental groups who will continue to campaign for federal legislation.**
- **The economy will continue to improve during the period 2013 to 2016 such that after the 2016 Presidential election, there could be more of a willingness among policymakers to consider some sort of climate change legislation.**
- **Potentially, with the support of the utility sector, some form of federal climate change legislation will be enacted in 2017 that would take effect in 2020.**

c. Please provide a detailed description of the methodology used to arrive at estimated future carbon costs discussed in question (a).

RESPONSE:

At the time Duke Energy Florida developed its current CO2 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, with the Republicans still in control of the House, and the Democratic majority in the Senate less than the 60 votes needed to invoke cloture, Duke Energy Florida sees no indication that climate change legislation designed to establish a price on CO2 emissions will be seriously debated through at least 2014.

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, Duke Energy Florida considers it unlikely that a carbon tax will be adopted in the near term because we do not believe the Republican-controlled House would support such a measure. Therefore, Duke Energy Florida does not believe that Congress will consider legislation in the near term that establishes a price on CO2 emissions.

While Duke Energy Florida 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 CO2 emissions. This is why Duke Energy Florida believes it is reasonable to consider such an outcome.

Duke Energy Florida'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 CO2 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. Duke Energy Florida is not predicting what form any such legislation may take.

The outcome of the legislative debate that occurred in 2009 and early 2010 is informative to the prices we are using today. As evidenced by the 2009 debate over the Waxman-Markey legislation, there are many strongly held differences of

opinion within the Democratic and Republican caucuses and between members of Congress representing different regions of the country regarding climate change legislation. It is not simply a Democrat versus Republican issue. For example, members of both parties from states with farm- and industrial-based economies expressed concerns about the impact of climate change legislation on manufacturing and energy prices; coal state members expressed concerns that climate change legislation would hurt the mining economy; and members from states that have historically relied on coal-fired generation expressed significant concerns over increased electric costs to consumers.

Duke Energy Florida believes a primary reason for the failure of climate change legislation in 2009 was concern that the legislation would lead to higher energy prices that would have had an adverse impact on the economy. It is reasonable to assume that this same concern will be present during any future debate over federal climate change legislation. In addition, regional differences, more than those between the political parties, could have a great bearing on the outcome of any future debate in Congress over climate change legislation that might occur. Reaching consensus on this issue will require compromise. At the end of the day, however, Duke Energy Florida believes that if Congress does enact legislation that sets a price on CO2 emissions, it will do so cautiously to minimize the impacts to the economy. Therefore, Duke Energy Florida believes that if Congress does enact climate change legislation establishing a price on CO2 emissions, it will not enact a program that will produce initially high prices so as to avoid shocking the economy. The reference case CO2 price forecast being used by Duke Energy Florida is consistent with the lower end of the range of prices that were predicted by the EPA for the Waxman-Markey legislation. Additionally, after the failure of the Waxman-Markey legislation, subsequent debate focused on the concept of a price collar that would set minimum and maximum prices for CO2. This concept is a cost control mechanism that demonstrates the concerns many had about enacting any program without cost containment so the policy would not adversely impact the economy.

Because of the uncertainty associated with potential future congressional action to pass legislation establishing a policy that would result in a price on CO2 emissions, Duke Energy Florida also considers an alternative scenario where the price on CO2 emissions is zero.

The EPA's recently proposed Clean Power Plan was not a consideration in the development of Duke Energy Florida's CO2 price forecast. Please refer to DEF's response to question 53h in the Staff's Interrogatories in Docket 140111 for a discussion of the EPA's proposed Clean Power Act and its potential influence on Duke Energy Florida's CO2 price forecast.

d. Please identify whether the carbon cost forecasts used in the instant case were derived in-house or by outside consultant(s). If the response is the latter, please identify each of these consultants and provide a copy of these analyses.

RESPONSE:

Duke Energy Florida's carbon cost forecast was developed in-house.

e. Please explain whether DEF used the analysis of past potential legislation for creating a market price for carbon as the basis for to developing its forecasted carbon costs discussed in question (a).

RESPONSE:

Duke Energy Florida did not directly use analyses of past potential legislation when it created its current carbon price forecast. We did, however, consider analyses of the 2009 Waxman-Markey legislation (H.R. 2454) as data points in the development of our forecast. Specifically, once we identified a potential price forecast, we compared it to the range of prices predicted by the EPA and the Energy Information Administration for the Waxman-Markey legislation to judge the reasonableness of our price forecast.

f. If the response to question (e) is affirmative, please provide an explanation of why DEF believes this approach to estimating the future cost of carbon is appropriate given the past legislation for creating a market price for carbon was not enacted.

RESPONSE:

As explained in our response to question 14e, while we did not use analyses of the Waxman-Markey legislation as a direct input into our decision making about our carbon forecast, we did use analyses of the Waxman-Markey legislation as a point of reference to assist us in judging the reasonableness of our forecast. While we recognize that the legislation was not enacted, it was in fact the first legislation of its kind to pass at least one house of Congress, meaning it had the support of many in Congress. In the absence of any formal or informal legislative or regulatory proposals at the time our current forecast was developed, we considered the Waxman-Markey legislation to be a reasonable representation of the stringency of climate legislation that Congress might consider passing in the future.

g. If the response to question (e) is negative, please describe other approaches or methodologies, if any, DEF considered in developing its carbon cost forecasts.

<u>**RESPONSE**</u>:

Duke Energy Florida's carbon price forecast primarily reflects our best judgment as to what a reasonable price trajectory might be given the fact that there was no legislative or regulatory proposals in play at the time our forecast was developed. Please also see our response to question 14c and 14f for additional discussion.

h. Does DEF plan to update or modify its carbon cost forecasts by taking into consideration EPA's recently published draft carbon emission guidelines for existing stationary sources for electric utility generating units (Clean Power Plan), which proposed a statewide CO_2 target for Florida? Please explain your answer.

<u>**RESPONSE**</u>:

Duke Energy Florida is currently evaluating whether it should update its carbon forecast in response to the EPA's recently proposed Clean Power Plan, and if so, how it should update the forecast. No decision has been made at this time. The issuance of EPA's Clean Power Plan proposal does not eliminate the uncertainty surrounding future carbon policy. For example, assuming the EPA finalizes the Clean Power Plan essentially as it has been proposed, there are multiple potential forms that state regulations implementing the requirements of the emission guidelines could take, and each would likely have a different associated cost. For example, regulations could take the form of a command-and-control type program, or they could take the form of some sort of emissions or emission rate averaging or trading program. The state of Florida could choose to implement its program only within the state's borders, or it could choose to join with other states in implementing the requirements of the EPA emission guidelines. The fact that there are still multiple potential pathways for implementation of carbon regulation in Florida in response to EPA's proposal makes determining the appropriate carbon cost forecast challenging. More will be known when EPA finalizes its proposal in June of 2015, but until the state develops its implementation plan, there will still be uncertainty. There is also the uncertainty that results from expected legal challenges to EPA's final emission guidelines and whether the courts will require changes to whatever EPA finalizes. Finally, there is the possibility that EPA's final emission guidelines could be substantially different from what has been proposed, which creates additional uncertainty.

i. What is DEF's expected implementation schedule for the proposed Clean Power Plan?

<u>RESPONSE</u>:

Duke Energy Florida's implementation schedule will be such that it supports meeting whatever regulatory requirements are placed on it by the state, but we do not have a specific schedule at this time because we are years away from knowing what those requirements will be. Based on the EPA's proposal, it is likely that some measures could be required to be implemented as early as 2020. The EPA has proposed that the interim compliance period extend from 2020 to 2029, with the final compliance period starting in 2030. The EPA asks for comment on an alternative approach that would have the interim compliance period extending from 2020 to 2024, with the final compliance period starting in 2025. Under section 111(d) of the Clean Air Act, the states have the responsibility for developing the source-specific regulations for implementing the emission guidelines that EPA establishes. The EPA's emission guidelines will therefore not impose regulatory requirements on any of Duke Energy Florida's affected power plants. Based on EPA's proposal, the state of Florida can take from June 2016 to June 2018 to finalize its regulatory plan and submit it to EPA for approval. EPA expects to take up to a year to review and approve or disapprove a state plan.

15. Referring to page 80, line 22, through page 81, line 2, of the testimony, please explain why the Company believes "[f]urther changes in ... carbon cost prices were unnecessary for DEF to understand that the Citrus County Combined Cycle Power Plant remained the most cost-effective resource option for DEF to meet its reliability need." What is the basis or evidence in support of this statement?

RESPONSE:

The referenced testimony in this Staff interrogatory is the conclusion of the explanation why DEF did not perform other sensitivity analyses besides the high natural gas price case and the no carbon cost case sensitivity analyses. At lines 13-22 on page 80, Mr. Borsch explains why further changes in the natural gas price or carbon cost prices were unnecessary for DEF to understand that the Citrus County Combined Cycle Power Plant remained the most cost-effective resource option for DEF to meet its reliability need.

16. Referring to Exhibit BMHB-1, the Need Determination Study:

a. Referring to page 46, please elaborate, in detail, on the statement "[t]he carbon price Duke Energy currently uses in its fundamentals forecast is a direct input to the process." What is meant by the term "the process" appearing in this statement? What basis or evidence does DEF rely on to support this statement?

RESPONSE:

The "process" referred to on page 46 of Exhibit BMHB-1, the Need Determination Study, is the process of developing the Company's fundamental fuels forecast. The development of the Company's fundamental fuels forecast is explained in detail in the testimony of Kevin Delehanty.

b. Referring to page 46, please explain why DEF believes the carbon price DEF currently used was "a reasonable trajectory to represent the risk of federal climate legislation or regulation given the current uncertainty surrounding such policy." What basis or evidence does DEF rely on to support this statement?

RESPONSE:

Please see DEF's response to Staff's Interrogatory 14.

c. Referring to page 86, please elaborate, in detail, on the statement "[t]his change in the differentials results from the effective removal of an efficiency penalty in the form of a charge for emissions rate." What basis or evidence does DEF rely on to support this statement?

RESPONSE:

CO_2 emission rates are directly tied to fuel consumption rates, so more efficient units emit lower levels of CO_2 per MWh. When CO_2 emissions costs are included in the variable production costs used to model dispatch, less efficient units (e.g. older combined cycles and peakers) which emit more

CO_2 per MWh will be penalized in the dispatch order and will effectively cost more to operate. The basis of this observation is that when more efficient units are added to the system, they are able to lower both fuel costs and emission costs, and when the emissions costs for CO_2 are added, they create an efficiency penalty because the less efficient units cost more to operate. When fleet portfolios are compared, the portfolios that include the less efficient generating units are more expensive to operate (i.e. penalized) when the emissions costs are added to the total production costs to serve the projected load.

17. Does DEF expect to reduce its fleet's average CO_2 emissions, in pounds per megawatt hour (lbs/MWh), with the addition of the proposed Citrus County Combined Cycle Power Plant? If so, what amount of CO2 emissions does DEF expect to save if the proposed Citrus County Combined Cycle Power Plant is put into service?

<u>RESPONSE</u>:

Yes. Based on the modeling results, the addition of the Citrus Combined Cycle Power Plant is projected to help lower fleet CO2 emissions in the range of roughly 90 lb/MWh.

This value is the result of comparing the average emissions for our base case from years 2013 through 2017, before the Citrus Combined Cycle Power Plant is in service, to the emissions rate in year 2019, the first full year that the Citrus Combined Cycle Power Plant is in service.

18. Please refer to page 27 of Exhibit No. BMHB-1. Witness Borsch states, "Citrus County Combined Cycle Power Plant is designed to comply with the anticipated requirements of the New Source Performance Standards for Greenhouse Gas Emissions." What are DEF's anticipated CO_2 emissions, in lbs/MWh, for the planned Citrus County Combined Cycle Power Plant?

<u>RESPONSE</u>:

Based on modeling projections, DEF's CO_2 emissions for the planned Citrus County Combined Cycle Power Plant are expected to be in the range of 780 – 800 lbs/Mwh. Based on the NPGU data, the value calculated for the unit is 782 lb/MMBtu based on an average heat rate of 6690 Btu/kWh and an emission rate of 117 lb.MMBtu.

For the purposes of the following questions, please refer to the Direct Testimony of Benjamin M.H. Borsch, Exhibit BMHB-2 (Duke Energy's 2014 Ten Year Site Plan).

19. For Schedule 2.1, please provide the following for Columns (5) & (8) respectively. Please provide this information in electronic format (Excel):

a. The Model Assumptions (rationale for variable selection and model specification).

RESPONSE:

The model assumptions and sources for column (5) are explicitly stated in Exhibit BMHB-2 page 28 of 76, General Assumptions #2 and #3. Service area population has consistently proven to be an excellent predictor of residential customer growth. By applying the Moody's projection of Florida household size, the projection captures the Great Recessions impact of population immobility and the recognized combination of households due to job loss and home foreclosure. For Column (8), the commercial class customer projection is driven by the amount of residential customers (3-month moving average), with the idea that commercial sector activity is driven to support the area population.

Please see Load Forecast Work Papers – Documentation…for file names Hist_HHolds-Pop-HHSize.xlsx_201309 and Itron ND Models_Inputs & Output files CUST_RES & CUST_COM bearing Bates numbers 14BGBRA-STAFFROG1-19a-DOC1 through 14BGBRA-STAFFROG1-19a-DOC 46. The document bearing Bates number 14BGBRA-STAFFROG1-19a-DOC 46 is confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

b. The Regression Equation(s).

RESPONSE:

Please see Load Forecast Work Papers – Documentation…for file names Hist_HHolds-Pop-HHSize.xlsx_201309 and Itron ND Models_Inputs & Output files CUST_RES & CUST_COM. Each Itron model is a multiple tabbed file with all requested information.

For input data sources see Exhibit BMHB-2 page 28 of 76, General Assumptions #2.

c. The Input Data Sets (if monthly – please specify ending month).

<u>RESPONSE</u>:

All answers for Items c. through g. can be found in Load Forecast Work Papers – Documentation.

d. The Input Data Sources.

<u>RESPONSE</u>:

See response to Interrogatory Number 19.c. above.

e. The Predicted Data Sets.

<u>RESPONSE</u>:

See response to Interrogatory Number 19.c. above.

f. The Model Output (variable coefficients, all statistical analyses).

<u>RESPONSE</u>:

See response to Interrogatory Number 19.c. above.

g. The Forecast Data Sets (monthly – specify starting month).

<u>RESPONSE</u>:

See response to Interrogatory Number 19.c. above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

<u>RESPONSE</u>:

Yes. The commercial class customer forecast was shifted upward by 500 customers for the whole forecast horizon to better capture the recent trend in history

20. For Schedule 2.1, please provide the following information for both Columns (6) & (9) respectively. Please provide this information in electronic format (Excel):

a. The Model Assumptions (rationale for variable selection and model specification).

RESPONSE:

The model assumptions with sources for column (6) & (9) are explicitly stated in Exhibit BMHB-2 page 28-30 of 76. The rationale for variable selection always involves an economic variable deemed statistically correlated to the "class" energy sales.

b. The Regression Equation(s).

RESPONSE:

All answers for Items b. through g. are identical to response Q19 c.

c. The Input Data Sets (if monthly – please specify ending month).

RESPONSE:

See response to Interrogatory Number 19.c. above.

d. The Input Data Sources.

RESPONSE:

See response to Interrogatory Number 19.c. above.

e. The Predicted Data Sets.

RESPONSE:
See response to Interrogatory Number 19.c. above.

f. The Model Output (variable coefficients, all statistical analyses).

RESPONSE:

See response to Interrogatory Number 19.c. above.

g. The Forecast Data Sets (monthly – specify starting month).

<u>**RESPONSE**</u>:

See response to Interrogatory Number 19.c. above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

<u>**RESPONSE**</u>:

Out of model adjustments only include estimated impacts for plug-in electric vehicle and rooftop photovoltaic panel saturation.

21. Please refer to page 35 of 76, section "Peak Demand Forecast." Please provide the following for both the "winter peak demand potential firm retail load forecast," and the "summer peak demand potential firm retail load forecast." Please provide the data in an electronic format compatible with Excel.

a. The Model Assumptions (rationale for variable selection and model specification).

RESPONSE:

The model assumptions for both the "winter peak demand potential firm retail load forecast," and the "summer peak demand potential firm retail load forecast" are based on the number of retail customers (excluding Street & Highway Lighting) drawing load on the DEF system at time of monthly peak. A determined effort to "add back" any historical direct load control (DLC) at time of monthly peak before commencing the modeling effort insures a consistent relationship between the independent variables and the dependent variable.

b. The Regression Equation(s).

RESPONSE:

All answers for Items b. through g. are identical to response Q19 c.

c. The Input Data Sets (if monthly – please specify ending month).

RESPONSE:

See response to Interrogatory Number 19.c. above.

d. The Input Data Sources.

RESPONSE:

See response to Interrogatory Number 19.c. above.

e. The Predicted Data Sets.

RESPONSE:

See response to Interrogatory Number 19.c. above.

f. The Model Output (variable coefficients, all statistical analyses).

RESPONSE:

See response to Interrogatory Number 19.c. above.

g. The Forecast Data Sets (monthly – specify starting month).

RESPONSE:

See response to Interrogatory Number 19.c. above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

RESPONSE:

Out of Model Adjustments are commonly made to projections of retail potential monthly peak demand, all with the intent to best capture the historical trend with known anomalies where either solid estimates exist, or does not exist. Retail monthly peak demand is expected to occur on a weekday. Winter month peaks are expected to occur in the morning at "normal" weather conditions. Summer month peaks always occur in late afternoon. Peaks during activated load control often are pushed off an hour or two when typical usage patterns are different than hour of expected peak. Weekend or holiday peaks often occur in the winter when normal winter peaking weather conditions do not occur on a week day. This will result in a lower peak load due to industry being at reduced levels or school load being off. Lastly, summer rain influence on peak demand is very difficult to measure. Capturing rain impact from weather station rainfall levels is "hit or miss" with the typical "localized" thunder storm patterns in Florida afternoons.

22. When was the load forecast discussed in witness Borsch's Direct Testimony prepared and was it reviewed by executive management? If so, what was the review process?

RESPONSE:

The load forecast in question was prepared in late fall 2013. DEF's load forecast is not reviewed by "executive management" given that the term "executive management" would mean Duke Energy's Senior Management Committee which consists of Duke Energy's most senior executives. However, DEF's load forecast is reviewed and approved by the Vice President of Corporate Strategy following section Director approval prior to it being used for planning purposes.

23. Please refer to Schedule 2.3, Column (2), titled "Sales for resale GWh." Please explain the significant drop in sales from 2013 (1,488) to 2014 (936).

RESPONSE:

This drop in "Sales for Resale GWh" is two-fold. First, weather conditions in 2013 were slightly milder than normal, but rainfall was extremely high reducing the need for energy under the DEF "peaking strata" contracts during the summer months. Second, DEF wholesale contracts for competitive spot market offers available to wholesale entities were not as competitive under market conditions resulting in a lower load factor in the projection of wholesale energy.

24. Please refer to Schedule 3.1, Column (4), titled "Retail." Please explain the significant increase in the retail summer peak demand from 2013 (9,000) to 2014 (9,555).

RESPONSE:

The retail summer peak of 8/12/2013 at hour ending 5pm occurred at a 5-Hr system weighted temperature of over two degrees Fahrenheit cooler than normal expected conditions. More than 0.5 inches of rainfall was recorded on this peak day at the Orlando weather station, DEF's largest load center.

Also, an expected 22,200 more retail customers are expected to be drawing load during the summer peak 2014.

25. Please refer to Schedule 3.2, Column (4), titled "Retail." Please explain the significant increase in the retail winter peak demand from 2013 (8,274) to 2014 (10,231).

RESPONSE:

The retail winter peak of 2/18/2013 at hour ending 8am occurred at a 2-Hr/24-Hr system weighted temperature of nearly four degrees Fahrenheit warmer than normal expected conditions. Also, this winter peak occurred on a Monday morning which typically has lower peaks than other weekday peaks - all else being equal. Weekend load patterns have not completely shifted to a typical weekday load pattern

Besides the reasons mentioned above not expected to occur in the winter of 2013/14, the number of retail customers expected to be on the DEF system at time of peak will be higher by 22,200.

26. Please provide the basis and supporting documentation for using 3.75 percent as the overall cost of debt capital as shown on Page 48 in Financial Assumptions Base Case Exhibit of the Duke Energy Florida Need Determination Study (BMHB-1) and again in the Duke Energy Florida Ten Year Site Plan Financial Forecast on Page 65 (BMHB-2).

RESPONSE:

The company estimated the incremental debt cost for its utility operating companies for the 2013 – 2017 financial planning period. The estimated utility operating company debt cost, including Duke Energy Florida, was determined utilizing forward US Treasury Yields and credit rating equivalent credit spreads appropriate for Duke Energy operating utility companies as of December 2012. The 3.75% debt cost for Duke Energy Florida is the average of the estimated 20-year implied debt costs for 2013 – 2017 financial planning period as summarized in the table below.

	10-year Utility Operating Debt Cost			30-year Utility Operating Debt Cost			(1) 20-year Implied Utility Operating Company Debt Cost
	US Treasury Yield	Credit Spread	Debt Cost	US Treasury Yield	Credit Spread	Debt Cost	**Debt Cost**
12/31/2012	1.76	0.88	2.64	2.92	1.13	4.05	**3.34**
6/30/2013	1.86	0.88	2.74	2.98	1.13	4.11	**3.43**
6/30/2014	2.10	0.88	2.98	3.12	1.13	4.25	**3.61**
6/30/2015	2.33	0.88	3.21	3.26	1.13	4.39	**3.80**
6/30/2016	2.55	0.88	3.43	3.39	1.13	4.52	**3.97**
6/30/2017	2.74	0.88	3.62	3.50	1.13	4.63	**4.12**
			3.20			4.38	**3.79**
Incremental 20-year Duke Energy Florida Debt Cost for the Financial Plan period 2013 - 2017:							**3.75**

(1) The 20-year Implied Debt Cost is the simple average of the 10-year and 30-year Debt Costs.

Source: Bloomberg Financial Services as of December 2012

27. Please provide the basis and supporting documentation detailing the 2.5 percent annual General Inflation Rate in Item 13 Financial Assumptions on Page 33 of the Duke Energy Florida Need Determination Study (BMHB-1).

RESPONSE:

The file attached in Bates range 14BGBRA-STAFFROG1-27-DOC1 provides the support for the determination to continue with the use of 2.5% for a general inflation rate in 2014. This document is confidential and is subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with service of this response.

The following questions refer to the direct testimony of Kevin Delehanty.

28. On page 7, the witness states that "EVA was selected based on, among other factors, its experience, modeling processes and tools, market and regulatory expertise." Please elaborate on EVAs qualifications with respect to each of the factors.

<u>RESPONSE</u>:

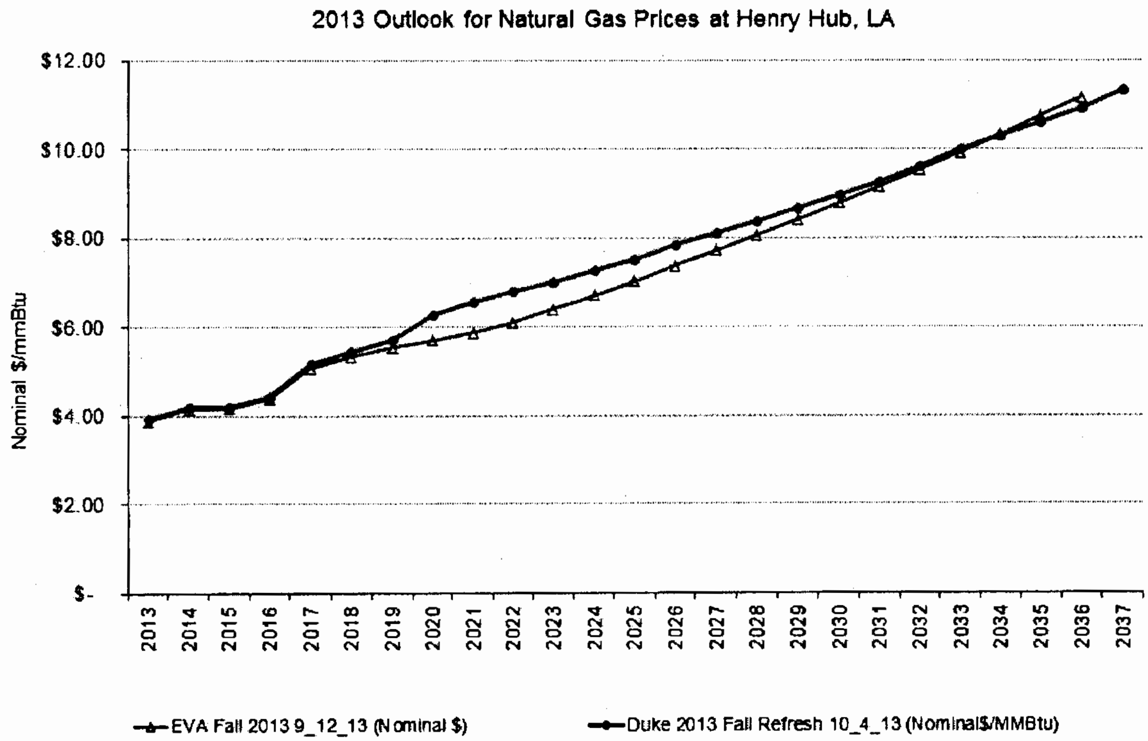
Duke Energy has been working with external energy consulting practices to produce a customized long term fundamental commodity price outlook since 2005. EVA is one of the energy consultants that Duke has used over the past nine years. What separates EVA from other industry recognized experts in fundamental forecasting of energy prices at this point in time is EVA's modeling approach, their proprietary upstream databases and their current staff at the time of the engagement. EVA has a core team of experts who have remained largely intact since the firms founding in 1981. This continuity is somewhat unique as Duke Energy has witnessed substantial personnel shifts at other firms. Duke Energy has purchased EVA's subscription based "Fuelcast" energy outlook since 2005 and has established a positive working relationship with their principal advisors. Duke has used the EVA outlook within the validation process of all of our previous corporate fundamental commodity price outlooks dating back to 2005. Furthermore, Duke Energy has retained EVA to provide expert testimony in past arbitration proceedings on fuel supply contracts and environmental permitting. Attached is document with the current resume of each member of EVA's staff as well as their proposal in response to Duke Energy's RFP in 2012, (with only the prices redacted). The 2012 EVA proposal discusses their modeling approach, tools and data sources. The Aurora model at the center of the EVA power price outlook is also an industry standard tool which is currently used by both CERA and Wood Mackenzie, other industry recognized experts in fundamental forecasting of energy prices. The upstream fuel database models are proprietary to EVA and contain a mix of public and private industry data sources. EVA provides Duke Energy a transparent process and access to their principle subject matter experts. EVA's process is very data driven and they are open to discuss potential changes to their current outlook as new information arises. EVA offers Duke Energy flexibility in the development of the Duke Energy long term fundamental fuel price outlook.

See documents attached in Bates range 14BGBRA-STAFFROG1-28-000001 through 14BGBRA-STAFFROG1-28-000085. Documents bearing Bates numbers 14BGBRA-STAFFROG1-28-000001 through 14BGBRA-STAFFROG1-28-000060 are confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

29. Referring to page 9, lines 5-18, please describe how the changes made by DEF impacted EVA's fundamental forecast (i.e. increased or decreased projected natural gas prices).

RESPONSE:

The assumption changes requested by Duke Energy to the Fall 2013 EVA reference case had a mixed impact on natural gas prices as some of the assumptions supported higher prices like carbon, while others reduced the demand for natural gas (lower load growth, increased renewables). The net effect of the changes was higher prices for natural gas from 2020 to 2030 in the Duke Energy case and this was primarily due to the carbon assumption. See chart below for a direct comparison.



The following questions refer to the direct testimony of Amy Dierolf.

30. On page 3, the witness states that the Citrus County Combined Cycle Power Plant "will be able to leverage existing facilities and minimize further impacts to land and water on the site." Please complete the table below summarizing the water usage at DEF's Crystal River Energy Complex.

	million gallons per day
2004	
2005	
2006	
2007	
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

RESPONSE:

Please see documents produced in Bates range 14BGBRA-STAFFROG1-30-DOC1.

31. Please refer to Exhibit AD-2 for the following question. What is the latest date that the Governor can sign the Siting Board Order without impacting the currently projected in-service date?

RESPONSE:

If the Governor and Cabinet (Siting Board) did not approve the Citrus Combined Cycle Project by the end of November 2015, it would likely impact the currently projected in-service date of the project.

The following questions refer to the direct testimony of Mark E. Landseidel.

32. On page 6, the witness states that one of the Citrus County Combined Cycle Power Plant power blocks "will be connected to the CREC 230kV transmission system, effectively replacing the CR Unit 1 and CR Unit 2 generation when those coal-fired plants are retired." Based on this statement, can the discussed power block only be connected to the transmission system if CR 1 and 2 are retired?

<u>RESPONSE</u>:

Yes, CR1 and 2 must be retired upon commercial operation of the CC power block that will be connected to the 230kV transmission system. During start-up and commissioning of this CC power block CR1 and 2 may be operated as required to meet DEF system needs until the CC power block achieves commercial operation.

33. On page 7, the witness states that "the plant will have moderate duct firing capability, which means 50 to 100 MWs of duct fired output of each 820MW block will be available as cost effective peaking capacity." Does this mean that each block would operate at 720 MW during base load periods?

RESPONSE:

It depends on ambient conditions. On a 90F summer day the unfired output will be 737MW and with 83MW of duct burning the power block output will be 820MW. On a 40F winter day the unfired output will be 836MW such that no duct burning is required for a 820MW power block output. Economic dispatch will determine when and how much duct burning output is required.

34. On page 9, the witness states that "Sabal Trail and DEF plan an additional receipt-only interconnect between Sabal Trail and Florida Gas Transmission Company, LLC ("FGT") in Citrus County, Florida." Please explain what is meant by a receipt-only interconnect.

RESPONSE:

The proposed interconnect of the Sabal Trail Citrus County Gas Lateral with FGT will only allow gas to flow one way, from FGT into the Citrus County Gas Lateral.

35. Referring to Exhibit No. MEL-4, please identify and provide the source(s) relied upon to develop the Citrus County Combined Cycle Power Plant Estimate.

RESPONSE:

Indicative pricing was obtained in 2013 for the major equipment (combustion turbines, steam turbines, heat recovery steam generators and generator step-up transformers). Burns & McDonnell was hired as Owner's Engineer and assisted in developing the plant scope and cost estimate. In addition an EPC contractor with significant advanced gas turbine plant experience in Florida was engaged to assist in the EPC contract portion of the estimate. The major equipment and EPC contract total more than 80% of the project cost (excluding AFUDC). In addition, Duke Energy's experience with combined cycle projects, was leveraged to build the project cost estimate including development of the Owner Cost portion of the estimate.

See also document attached bearing Bates number 14BGBRA-STAFFROG1-35-000001 through 14BGBRA-STAFFROG1-35-000026. This document is confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

36. Please identify and explain any costs contained in Exhibit No. MEL-4, that are excluded or included in the table titled "Construction Costs" found on page 19 of DEF's Need Determination Study.

RESPONSE:

All costs in Exhibit No. MEL-4 are included in the reference table in DEF's Need Determination except for AFUDC.

Construction Costs p. 19 of DEF's Need Determination.

$M	2013	2014	2015	2016	2017	2018	2019	Total
Engineering, Procurement, Construction, and Major Equipment	-	48.6	174.2	283.8	494.3	96.4	17.4	1,114.7
Owner Cost and BOP Equipment	2.8	11.8	14.3	24.2	89.1	44.1	0.1	186.5
Transmission Switchyard and Bus Line	-	-	-	4.9	41.2	2.4	-	48.5
Annual Cash Flow	**2.8**	**60.4**	**188.6**	**312.8**	**624.6**	**143.0**	**17.6**	**1,349.7**

37. On page 13 the witness states that DEF has "successfully executed several combined cycle gas turbine projects with [its RFP process] including Buck, H.F. Lee, Dan River, and Sutton." Please complete the table below summarizing the actual and originally projected costs of past DEF combined cycle projects.

	Originally Project Cost ($Millions)	Actual Cost ($Millions)
Buck		
H.F. Lee		
Dan River		
Sutton		

RESPONSE:

	Originally Project Cost ($Millions including AFUDC)	Actual Cost ($Millions including AFUDC)
Buck	$660	$664
H.F. Lee	$903	$715
Dan River	$709	$662
Sutton	$731	$560

38. Please complete the table below for Buck, H.F. Lee, Dan River, and Sutton.

Net Generation MW (Summer)	
Installed Cost ($ Million)	
Fixed O&M ($/kw-yr)	
Variable O&M ($/MWh)	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	
In-Service Date	
Location	

RESPONSE:

Please refer the attached confidential file entitled "140110)Staff_1st_ROG_38.xlsx" bearing Bates numbers 14BGBRA-STAFFROG1-38-DOC1. This document is confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

39. On page 9, of witness Scott's testimony, the witness states that "Power Grid is a recognized electric utility engineering company with substantial expertise in modeling transmission systems." Please discuss in detail Power Grid's experience in modeling transmission systems.

<u>**RESPONSE**</u>:

PowerGrid Engineering, Inc. is a consulting firm that has extensive experience (approximately 29 years) in performing Transmission Planning and Bulk Power System Studies. Experience has been obtained among several electric utilities and generator companies across the southeast. These include Southern Company Services, Dominion Virginia Power, Duke Energy Florida, Pioneer Green, Brookfield Renewable, Municipal Electric Authority of Georgia (MEAG Power) and Tampa Electric (TECO Energy). Study analysis experience includes Thermal/Voltage, Stability (Transient, Small Signal, Voltage), P-V, Short Circuit, Interface Evaluation and any other analysis associated with Generation Interconnection Studies.

40. Please refer to page 14, lines 6-15, of witness Taylor's testimony for the following questions.

a. Please discuss in detail how transmission and gas transportation estimates, provided by DEF, were found to be fairly balanced and consistent from a $/kW standpoint. Please include any documents or other evidence relied upon for this finding.

RESPONSE:

Sedway Consulting primarily relied upon the evidence provided in Tables A-2 and A-4 of the Independent Evaluation Report included in Exhibit No.__(AST-1) of Mr. Taylor's testimony for the comparative analysis of gas transportation and transmission estimates, respectively. Table A-2 depicted the normalized $/kW CPVRR impact of the gas transportation reservation charges for the NPGU, all outside proposals, and the generic resources that were packaged with the outside proposals to formulate complete portfolios. These costs ranged from $0/kW to $1,158/kW, with the NPGU's estimate near the top end of the range at $1,086/kW. The $/kW gas transportation charges for the generic resources were significantly less than the NPGU, thereby providing an economic benefit for outside proposals (relative to the NPGU) when such generic resources were combined with them. The transmission network upgrade assumptions in Table A-4 ranged from $0 to $95 million, with the NPGU's estimate near the middle of the range at $40 million. On a $/kW basis, the NPGU transmission costs were lower than virtually all other resources – a circumstance that DEF explained and attributed to the favorable transmission location of the NPGU near the retired Crystal River nuclear generating units.

b. Please describe the process followed to conclude that nothing was "out of line" with respect to transmission and gas transportation estimates provided by DEF. Please identify and include any documents or other evidence relied on by DEF in reaching this conclusion.

RESPONSE:

Mr. Taylor of Sedway Consulting reviewed the detailed fuel and transmission cost files provided by DEF and attached to this response as

Confidential Attachments 1 and 2 to Staff ROG 1-40(b) in Bates range 14BGBRA-STAFFROG1-40b-DOC1 through 14BGBRA-STAFFROG1-40b-DOC3 and subject to DEF's Sixth Notice of Intent to request confidential classification. First, Mr. Taylor found the component costs to be reasonable and in line with similar types of costs seen in other power supply solicitations around the country. Second, he reviewed the costs on a total dollar and $/kW basis as discussed in the response to part (a) above and found the costs to be fairly balanced and not exhibiting any bias for or against any proposed resource. Third, he reviewed the final evaluation results and determined that the selection decision was not affected by any differences in the gas transportation and transmission cost assumptions between resources. In other words, if a hypothetical average $/kW value had been applied uniformly to all resources for these cost assumptions, it would not have changed the selection decision.

41. On page 14 of witness Taylor's testimony, the witness states that he "was free to use or modify the estimated costs in any way [he] deemed appropriate – and indeed did so, in line with evaluation processes that Sedway Consulting has employed in other resource solicitations."

a. Please identify the modifications made by witness Taylor.

RESPONSE:

Mr. Taylor employed a different methodology than DEF for converting transmission network upgrade capital cost estimates into cost impacts. Mr. Taylor calculated levelized annual transmission revenue requirements (assuming a 40-year transmission asset life) for each resource's applicable investment and applied those annual costs only during the term of the PPA (or economic life of the asset in the case of owned generation options).

b. Please describe with specificity why the discussed modifications were made.

RESPONSE:

Sedway Consulting has employed this methodology in other solicitations around the country – either as a base case or sensitivity process. The methodology is premised on the assumption that a transmission investment may provide benefits to a utility's customers after a PPA has expired (e.g., enhanced reliability of the utility's transmission system, improved access to future cost-effective generating resources, increased transmission capacity for selling point-to-point service to and acquiring revenues from new transmission customers). Sedway Consulting's methodology essentially equates these potential benefits or future revenues to the levelized transmission revenue requirements associated with the post-PPA period. Therefore, those post-PPA transmission costs are not added to the cost analysis for the PPA. This results in a lower final CPVRR transmission cost for all resources.

c. Please discuss the impact the modification made on the CPVRR analysis performed by witness Taylor.

RESPONSE:

Because all of the proposed resources in DEF 2018 RFP were fairly long term, Sedway Consulting's methodology did not yield significant CPVRR differences from the approach followed by DEF. The table below depicts the

CPVRR differences for the two approaches. The first column is the CPVRR impacts associated with Sedway Consulting's methodology, as reported in Table A-4 of Sedway Consulting's Independent Evaluation Report included in Exhibit No.__(AST-1) of Mr. Taylor's testimony. The second column reflects the CPVRR impact of including the full 40-year transmission revenue requirements for each proposed resource. The third column depicts the difference.

Response to Staff ROG 1-41(c)
Transmission Network Upgrade Methodology CPVRR Impact
($M)

Resource/Proposal	Sedway Consulting Methodology	Full Transx CPVRR	Difference
Proposal A	96	114	18
Proposal B	0	0	0
Proposal C1	83	121	38
Proposal D1	59	69	10
Proposal E1	59	69	10
Proposal F	57	66	9
NPGU	N/A*	N/A	N/A
Side-Fill-May	37	38	1
Side-Fill-Dec	36	37	1
Back-Fill (2040)	9	17	8

*Included in base revenue requirements for NPGU.

42. Please complete the table below summarizing the results of DEF's fuel cost forecast. Please provide this information for the fuel forecast used in this docket, the Company's most recent rate case, the Company's Ten Year Site Plan filed in 2014, and in Docket No. 130200-EI.

	Delivered Fuel Price Forecast (Nominal)		
	Natural Gas ($/MMBtu)	Oil ($/MMBtu)	Coal ($/MMBtu)
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			

2046			
2047			
2048			
2049			
2050			

RESPONSE:

Please see the table attached to this response bearing Bates number 14BGBRA-STAFFROG1-42-DOC1.

The table shows price forecasts for the current docket and for the 2009 DSM goal setting docket. The forecast for the current docket is the same as that used in the 2014 Ten-Year Site Plan and as that used in Docket 130200-EI. The forecast used in the last (2009) rate case presented only a single year (2010) forecast.

43. Witness Delehanty discusses DEF's fundamental fuel forecast.

a. Please identify and describe the inputs and assumptions used in developing the fuel cost forecast(s).

<u>RESPONSE</u>:

The fuel cost forecasts are constructed for each generation facility by combining three to five years of visible futures market prices with a long term fundamental price forecast beyond year five and then adding in plant specific transportation costs and fees. Fuel prices beyond 2033 were calculated by smoothing the final five years of fundamental prices and then escalating those prices beyond the final forecast year (2037) at a long term escalation rate of approximately 3% /yr. The market prices for the initial five years originate from liquid trading hubs like the New York Mercantile Exchange (NYMEX) as well as broker quotes, contracts and responses to fuel supply RFP's.

The primary inputs and assumptions used in DEF's fundamental forecast are contained within the 2013 EVA Long Term "Fuelcast" Outlook, published in the Fall of 2013 as well as a list of assumptions requested by Duke Energy. Duke Energy subject matter experts reviewed EVA's 2013 outlook as well as their input assumptions and requested specific changes to better align the forecast with Duke Energy's own internal planning assumptions. It is important to note that Duke Energy adopted all of EVA's upstream supply and demand data assumptions for the oil, gas and coal sectors, which means that Duke Energy did not adjust the fuel supply curves, or any of the demand curves outside of the power sector. Duke Energy limited its assumption changes to areas within the power sector, and areas of environmental and regulatory policy where Duke energy feels it has attained a level of subject matter expertise. Please see the excel workbooks: attachment (###) <2013_09_06 - FuelCast 2013 LT - Modeling Assumptions.xlsm> for a list of EVA's input assumptions and attachment (###) <2013 Fall Refresh Duke Assumption Changes.xlsx > for the specific changes requested by Duke Energy.

Please see documents attached bearing Bates numbers 14BGBRA-STAFFROG1-43a-DOC1 through 14BGBRA-STAFFROG1-43a-DOC2. These documents are confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

b. Please identify all third party consultants relied upon in developing the fuel cost forecast(s) and provide copies of their reports or other analyses.

RESPONSE:

Duke Energy only relied upon EVA's Fall 2013 Long Term Outlook (Fuelcast) in the development of the Duke Energy Fall 2013 Fundamental Forecast. Duke Energy did however utilize other third party forecasts in the validation process to verify the reasonableness of the Duke Energy outlook and to help set the appropriate range for fuel price sensitivities.

c. Please identify each difference in DEF's fuel forecast methodology used in this docket when compared to: 1) the Company's most recent rate case, 2) the Company's Ten Year Site Plan filed in 2014 and 3) the company's methodology used in Docket No. 130200-EI.

RESPONSE:

DEF's most recent rate case was in 2009 and in that docket only a one year projection was provided which had been developed in late 2008. The forecast methodology used in 2008 relied on forecasts from two industry recognized consultants PIRA and Global Insight, DEF used a numerical average of the two. The forecast used in this docket is considerably different that the one constructed in 2008, but that has less to do with the methodology than the significant changes to the energy industry over the past six years. At that time, neither the full effects of the new technologies in unconventional gas development, nor the full impacts of the recession, were known. Gas prices were projected to be above $8 (2008$) for the foreseeable future, and coal prices were supported by higher load and lack of competition from inexpensive gas. In the longer term, at that time, a carbon emission price of $25 - $50 per ton was anticipated beginning in the 2014 - 2016 timeframe which would depress the long term price of coal and further inflate the price of gas. The methodology described in part a) is now used in all Duke Energy jurisdictions and the resulting forecast is consistent with the long term outlook for the company. The same fuel price forecast used in this docket was also used in the company's Ten Year Site Plan filed in 2014 as well as Docket No. 130200-EI.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of July, 2014, 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) 1 through 27, 42 and 43c from FLORIDA PUBLIC SERVICE COMMISSION STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-43) in Docket No. 140110-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Sandra L Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

35427768.1

AFFIDAVIT

STATE OF ~~FLORIDA~~ North Carolina

COUNTY OF ~~PINELLAS~~ Mecklenburg

I hereby certify that on this 15th day of July, 2014, 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 responses to interrogatory number(s) 32 through 38 from STAFF'S FIRST INTERROGATORIES NOS. 1-43 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140110-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 15th day of July, 2014.

Mark E. Landseidel

MURIEL R. SPEAR
NOTARY PUBLIC
Mecklenburg County
North Carolina
My Commission Expires ________

Notary Public
State of ~~Florida~~, at Large North Carolina

My Commission Expires:
October 20, 2018

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 15th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kevin Delehanty, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory number(s) 28, 29 and 43a-43b from STAFF'S FIRST INTERROGATORIES NOS. 1-43 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140110-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 15th day of July, 2014.

Kevin Delehanty
Kevin Delehanty

Nancy H. Taylor
Notary Public
State of Florida, at Large

NANCY H. TAYLOR NOTARY PUBLIC MECKLENBURG COUNTY, NC

My Commission Expires:
January 26, 2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 18th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Amy Dierolf, who is personally known to me, and she acknowledged before me that she provided the responses to interrogatory number(s) 30 and 31 from STAFF'S FIRST INTERROGATORIES NOS. 1-43 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140110-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of July, 2014.

Amy C Dierolf

Amy Dierolf

Jennifer Garwood

Notary Public
State of Florida, at Large

JENNIFER GARWOOD
MY COMMISSION EXPIRES March 22, 2016
#EE 148233
Bonded thru Budget Notary Services
NOTARY PUBLIC, STATE OF FLORIDA

My Commission Expires: 03/22/16

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 17th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ed Scott, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 39 from FLORIDA PUBLIC SERVICE COMMISSION STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-43) in Docket No. 140110-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 17th day of July, 2014.

Ed Scott

Sandra Cope

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

35878802.1

AFFIDAVIT

STATE OF COLORADO)

COUNTY OF BOULDER)

I hereby certify that on this 16th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Alan S. Taylor, who is personally known to me or has provided COLORADO DRIVER'S LICENSE as identification, and he acknowledged before me that he provided the responses to interrogatory numbers 40 and 41 from STAFF'S FIRST INTERROGATORIES NOS. 1-43 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140110-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 16th day of July, 2014.

Alan S. Taylor

Alan S. Taylor

SARA KUMBARJI
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20094000406
MY COMMISSION EXPIRES 1/6/2017

Sara Kumbarji

Notary Public
State of Colorado, at Large

My Commission Expires:
1/6/17

94

DEF's responses to Staff's Second Set of Interrogatories, Nos. 44-49

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 94
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Second Set of Interrogatories, Nos. 44-49.
[Bates Nos. 00065-00072]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI SERVED: JULY 23, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 44-49)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Second Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 44-49) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's Second Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 44-49), served on July 18, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

44. Please identify all the filings, docketed and undocketed, at the Florida Public Service Commission containing the same fuel price forecast as DEF's Fundamental Forecasts used in developing its base case in this proceeding.

RESPONSE:

DEF used the same fuel price forecast in this docket, Docket No. 140111-EI, Docket No. 130200-EI, and the Ten Year Site Plan Filing in 2014.

45. Please identify the dates when DEF's short term and long term fuel price forecasts provided as the fuel price input to DEF's base case in this proceeding were begun and completed and the major milestones from start to finish.

RESPONSE:

The DEF long term fundamental forecast used in this filing was considered a Fall update to the 2013 Duke Long Term Fundamental Forecast which was completed in the Spring of 2013. The justification for updating the Duke outlook in the Fall of 2013 was primarily due to EVA's new reserve estimates for natural gas which were the result of new data from the US Potential Gas Committee report published in April 2013. The timeline began with EVA delivering the initial sections of their Fall 2013 outlook (dubbed "Fuelcast") on 9/6/2013 and then EVA continued to send additional sections of the forecast throughout the month of September 2013. Duke reviewed the EVA forecast sections as they received them and immediately began outlining the requested assumption changes to be used in the development of the Duke outlook. The review process and assumption changes occurred primarily during the month of September 2013. EVA then re-ran their models and began producing initial results in early October 2013 and delivered the final components of the Duke Energy 2013 Fall Refresh forecast on 10/22/2013. The validation of the Fall update to the 2013 Duke Energy Fundamental Forecast began in October 2013 and was completed in early November 2013. The Short Term fuel price forecast is based on a snapshot of "futures market" price quotes on the New York Mercantile Exchange (NYMEX) on 10/18/2013, and the transportation cost estimates were updated on 12/31/2013.

46. If the level of CO2 emissions regulations assumed by DEF in preparing its Fundamental Forecast as discussed in witness Delehanty's direct testimony, page 11 is less or more restrictive than the regulations reflected in the U.S. EPA 6/2/14 Clean Power Proposal, what are the expected impacts on fuel prices relative to DEF's Fundamental Forecast provided in this proceeding?

RESPONSE:

Duke Energy has not yet evaluated the potential impact of the EPA's Clean Power Proposal on fuel prices. The proposed rule as currently structured, requires each state to submit a state level implementation plan (SIP) to the EPA which will achieve the targeted emissions rate by 2030 (or earlier at a higher target rate). Given the complexity of the proposed rule and the various avenues the individual states may choose, it is difficult to assess what the impact will be on the aggregate demand for natural gas in the United States relative to the assumptions used in the 2013 Fall update to the Duke Energy forecast which included a national carbon tax.

47. What were the contemporary, well-recognized industry natural gas price forecasts (forecasts source and fuel price data) DEF used to compare to its Fundamental Forecast referenced in witness Delehanty's direct testimony, page 11, lines 19-22?

RESPONSE:

Duke Energy used the following natural gas price forecasts:

a. Wood Mackenzie Fall 2013 Long Term View

b. PIRA October 2013 Long Term Outlook

c. EVA Fall 2013 Long Term Outlook

d. EVA Fall 2013 C02 Sensitivity to the Long Term Outlook

e. ESAI Fall 2013 Long Term Base Case

f. Energy Information Agency 2013 Annual Energy Outlook

g. BENTEK Fall 2013 Reference Case for the MISO Transmission Owners Group

48. Provide the calculations and data showing the development of the "statistically relevant deviations to the data" used to compare DEF's Fundamental Forecast to other natural gas price forecasts as referenced in witness Delehanty's direct testimony, page 11, lines 19-22.

RESPONSE:

Please see the confidential workbook entitled "Fall_2013_gas price_sensitivities.xlsx" previously produced in Bates range 14BGRBA-OPCPOD1-4a-0254—0256.

49. Please describe each of the changes and assumptions broadly identified in witness Delehanty's direct testimony, page 9, lines 5-18, (e.g. "coal plant retirement assumptions for existing coal plants") which DEF made to the EVA Fundamental Forecast.

<u>RESPONSE</u>:

Duke Energy reviewed the list of early coal plant retirements submitted by EVA and compared it to previous lists of coal retirements assumed by Duke Energy in prior forecasts. EVA used an economic standard as well as an age limitation in determining their assumed candidates for retirement. In prior fundamental forecasts, Duke Energy screened coal units by analyzing whether the units would generate sufficient economic margin to cover the required capital expenses associated with installing the necessary environmental controls. The types of "necessary" controls were determined by meeting an equipment based standard of compliance with MATS, CSAPR, 316b, and CCR. Where the two methodologies came to different conclusions on a particular unit, Duke Energy looked to available public disclosures offered by the owner of the coal unit to decide whether to assume a coal retirement or not. The differences in net coal generation were not very large as most of the coal units were either small in size and/or they ran at low capacity factors. In total, EVA assumed the early retirement of 527 coal units representing 72,280 MW's of capacity (nameplate ratings). Duke Energy assumed 488 coal units retire early, representing 66,329 MW's of capacity (nameplate ratings). Please see the confidential workbook entitled: "Retirements Final.xlsx" previously produced in Bates range 14BGBRA-OPCPOD1-41-0276.

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 22nd day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kevin Delehanty, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory numbers 44-49 from STAFF'S SECOND INTERROGATORIES NOS. 44-49 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140110-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 22nd day of July, 2014.

Kevin Delehanty
Kevin 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

95

DEF's responses to Staff's Third Set of Interrogatories, Nos. 50-54

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 95
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Third Set of Interrogatories, Nos. 50-54.
[Bates Nos. 00073-00082]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI DATED: August 12, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES TO <u>DUKE ENERGY FLORIDA, INC. (NOS. 50-54)</u>

Duke Energy Florida, Inc. ("DEF") responds to Staff's Third Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 50-54) as follows:

<u>GENERAL AND SPECIFIC OBJECTIONS</u>

DEF incorporates and restates its General and Specific Objections to Staff's Third Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 50-54), served on August 4, 2014, as if those objections were fully set forth herein.

<u>INTERROGATORIES</u>

50. Assuming approval of the proposed project, what does DEF anticipate the base rate increase would be when the proposed project is placed in service?

<u>RESPONSE</u>:

DEF estimates a residential base rate increase of approximately $6.55 on a 1,000 kWh bill.

51. Please complete the table below summarizing DEF's projected generation additions and retirements assuming the Company's proposed expansion plan. Please include summer capacity values for each addition and retirement.

	Generation Additions	Generation Retirements
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		

RESPONSE:

DEF's projected generation additions and retirements in the Company's proposed expansion plan.

	Generation Additions	MWs	Generation Retirements	MWs
2014	Orlando Cogen Additional Capacity	36	Lake County Contract Expires Turner 3 Retires	13 53
2015				
2016	Orange County Additional Capacity Southern Franklin Contract Suwannee CTs	30 425 316	Crystal River 1 Deration Crystal River 2 Deration Turner 1 Retirement Turner 2 Retirement Rio Pinar Retirement Avon Park 1 Retirement Avon Park 2 Retirement Southern Scherer Contract Expires Southern Franklin Contract Expires Suwannee Steam Units Retirement	50 79 10 10 12 24 24 71 342 128
2017	Hines 1-4 Inlet Chillers Uprate	220		
2018	Citrus Combined Cycle	1640	Crystal River 1 Retirement Crystal River 2 Retirement	320 420
2019				
2020			Higgins 1 Retirement Higgins 2 Retirement Higgins 3 Retirement Higgins 4 Retirement	20 25 30 30
2021	Combined Cycle 2x1	793	Southern Franklin Contract Expires	425
2022				
2023			Orlando Contract Expires	115
2024	Combined Cycle 2x1	793	Shady Hills Contract Expires Mulberry Contract Expires	476 115
2025			Orange County Contract Expires	104
2026	Simple Cycle	187		
2027	Combined Cycle 2x1	793	Vandolah Contract Expires	639
2028				
2029	Simple Cycle	187		
2030	Simple Cycle	187		
2031				
2032	Simple Cycle	187		
2033				
2034	Simple Cycle	187	Florida Power Development Biomass	60

2035				
2036	**Combined Cycle 2x1**	**793**		
2037				
2038				
2039				
2040				
2041				

52. For the purposes of the following interrogatory, please refer to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-2, Page 18 of 76. This exhibit presents DEF's Base "History and Forecast of Summer Peak Demand – Base Case."

a. Please provide the Company's High Case, and Low Case forecast Summer Peak Demand.

RESPONSE:

DEF does not have a High Case and Low Case forecast for Summer Peak Demand. The Company uses a robust load forecasting methodology which examines forecasts of economic growth and historic weather and customer usage. Given the detailed analysis used to develop the load forecast, the Company determined that sensitivities would not yield markedly different results.

b. Please provide the bases for how the High Case and Low Case Forecasts were developed.

RESPONSE:

DEF does not have a High Case and Low Case forecast for Summer Peak Demand.

53. For the purposes of the following interrogatory, please refer to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-2, Page 19 of 76. This exhibit presents DEF's Base "History and Forecast of Winter Peak Demand – Base Case."

a. Please provide the Company's High Case and Low Case forecast of Winter Peak Demand.

<u>RESPONSE</u>:

DEF does not have a High Case and Low Case forecast for Winter Peak Demand. The Company uses a robust load forecasting methodology which examines forecasts of economic growth and historic weather and customer usage. Given the detailed analysis used to develop the load forecast, the Company determined that sensitivities would not yield markedly different results.

b. Please provide the bases for how the High Case and Low Case Forecasts were developed.

<u>RESPONSE</u>:

DEF does not have a High Case and Low Case forecast for Winter Peak Demand.

54. Please complete the two charts below. Staff is seeking DEF's Summer and Winter Peak Demand Forecasts accuracies (error in percentage terms) for the years 2009 - 2013. The "Forecast Development Year" axis displays the years in which the forecast was made. The "*Forecasted Years*" axis displays the years being forecasted. Please also provide a brief explanation of what the Company believes led to error rate.

a. Summer

	FORECASTED YEARS			
Forecast Development Year	*2010*	*2011*	*2012*	*2013*
2009				
2010				
2011				
2012				

b. Winter

	FORECASTED YEARS			
Forecast Development Year	*2010*	*2011*	*2012*	*2013*
2009				
2010				
2011				
2012				

RESPONSE:

a Summer: The summer forecasted accuracy table is shown below:

Forecast Development Year	FORECASTED YEARS			
	2010	*2011*	*2012*	*2013*
2009	-3.1%	-4.8%	-7.1%	-10.9%
2010		-3.4%	-4.9%	-8.5%
2011			-5.1%	-5.2%
2012				-7.6%

The summer peak demand forecast variances are attributed to an unusually weak economic recovery from the Great Recession, including the associated prolonged recovery of the Florida housing market. Annual forecast input assumptions from Moody's Analytics and the University of Florida's Bureau of Economic & Business Research contributed to these variances as well since they were constantly revised during this time period due to changing projections of Florida economic activity or population growth over time.

b Winter: The winter forecasted accuracy table is shown below:

Forecast Development Year	FORECASTED YEARS			
	2010	*2011*	*2012*	*2013*
2009	2.9%	-9.8%	-25.2%	-24.3%
2010		-5.5%	-20.2%	-18.4%
2011			-18.1%	-13.5%
2012				-11.5%

The winter peak demand forecast variances are attributed to an unusually weak economic recovery from the Great Recession, including the associated prolonged recovery of the Florida housing market. Annual forecast input assumptions from Moody's Analytics and the University of Florida's Bureau of Economic & Business Research contributed to these variances as well since they were constantly revised during this time period due to changing projections of Florida economic activity or population growth over time.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 21st day of August, 2014, 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 50-54 from STAFF'S THIRD SET OF INTERROGATORIES (Nos. 50-54) in Docket No(s). 140110-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 21st day of August, 2014.

Benjamin M.H. Borsch

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

36051545.1

96

DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 55-56

See also: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 96
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 55-56. See also file contained on Sta...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

RECEIVED AUG 21 2014 FLORIDA PUBLIC SERVICE COMMISSION OFFICE OF THE GENERAL COUNSEL

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI DATED: AUGUST 20, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 55-56)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fourth Set of Interrogatories (Nos. 55-56) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Fourth Set of Interrogatories Nos. 55-56, served on August 18, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

55. Please complete the table below summarizing the revenue requirements associated with the two generation expansion plans compared in Exhibit No. BMHB-16.

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2029								
2030								
2031								
2032								
2033								
2034								
2035								
2036								
2037								
2038								
2039								
2040								
2041								
2042								
2043								
2044								
2045								
2046								
2047								
2048								
2049								
2050								
2051								
2052								
2053								
Total								

RESPONSE:

Base Case (TP1)

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month *
2018	71	(0)	74	1,704	28	328	2,204	$ -
2019	150	0	68	1,727	26	320	2,291	$ -
2020	137	(0)	79	1,776	297	313	2,602	$ -
2021	171	20	77	1,734	298	284	2,584	$ -
2022	187	32	74	1,690	299	264	2,546	$ -
2023	170	29	73	1,651	313	259	2,494	$ -
2024	188	32	72	1,601	315	159	2,367	$ -
2025	193	33	69	1,564	310	75	2,244	$ -
2026	180	32	68	1,532	319	28	2,158	$ -
2027	204	46	65	1,492	320	15	2,142	$ -
2028	238	58	62	1,463	315	9	2,144	$ -
2029	235	56	59	1,426	319	9	2,104	$ -
2030	214	51	58	1,385	327	8	2,043	$ -
2031	195	46	56	1,351	339	8	1,995	$ -
2032	177	42	55	1,323	349	7	1,953	$ -
2033	161	38	53	1,286	356	7	1,901	$ -
2034	146	35	52	1,248	356	7	1,842	$ -
2035	132	31	50	1,213	357	6	1,790	$ -
2036	146	40	48	1,179	353	6	1,773	$ -
2037	150	44	46	1,142	350	5	1,738	$ -
2038	135	40	44	1,104	353	5	1,682	$ -
2039	123	36	43	1,067	357	5	1,630	$ -
2040	111	33	42	1,034	357	5	1,582	$ -
2041	101	30	40	1,000	361	4	1,535	$ -
2042	91	27	39	966	364	4	1,491	$ -
2043	83	24	38	934	364	4	1,447	$ -
2044	75	22	37	896	364	4	1,398	$ -
2045	68	20	35	858	363	3	1,348	$ -
2046	62	18	34	822	361	3	1,300	$ -
2047	56	16	33	787	361	3	1,256	$ -
2048	51	15	31	756	361	3	1,216	$ -
2049	46	13	30	723	358	3	1,173	$ -
2050	42	12	29	692	358	2	1,135	$ -
2051	38	11	28	662	358	2	1,099	$ -
2052	34	10	27	635	357	2	1,064	$ -
2053	28	9	26	607	345	2	1,017	$ -

Notes:
* Residential bill impact displayed as a differential from TP1. 1,200 kWh/month rate based on average residential price.

CRS Retirement and Citrus in Service Date delayed by 1 year

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month *
2018	0	(0)	66	1,745	39	331	2,181	$ (1.26)
2019	68	0	60	1,795	38	333	2,294	$ (0.29)
2020	145	(0)	79	1,776	302	313	2,615	$ 0.58
2021	178	20	77	1,734	298	284	2,591	$ 0.37
2022	193	32	74	1,690	299	264	2,552	$ 0.35
2023	176	29	73	1,651	313	259	2,500	$ 0.34
2024	193	32	72	1,601	315	159	2,373	$ 0.32
2025	198	33	69	1,564	310	75	2,249	$ 0.30
2026	184	32	68	1,532	319	28	2,163	$ 0.30
2027	208	46	65	1,492	320	15	2,146	$ 0.29
2028	242	58	62	1,463	315	9	2,148	$ 0.28
2029	239	56	59	1,426	319	9	2,107	$ 0.28
2030	217	51	58	1,385	327	8	2,046	$ 0.27
2031	198	46	56	1,351	339	8	1,998	$ 0.27
2032	180	42	55	1,323	349	7	1,956	$ 0.26
2033	163	38	53	1,286	356	7	1,903	$ 0.25
2034	148	35	52	1,248	356	7	1,845	$ 0.25
2035	134	31	50	1,213	357	6	1,793	$ 0.25
2036	148	40	48	1,179	353	6	1,775	$ 0.24
2037	151	44	46	1,142	350	5	1,739	$ 0.23
2038	137	40	44	1,104	353	5	1,684	$ 0.21
2039	124	36	43	1,067	357	5	1,632	$ 0.18
2040	112	33	42	1,034	357	5	1,583	$ 0.16
2041	102	30	40	1,000	361	4	1,536	$ 0.16
2042	92	27	39	966	364	4	1,492	$ 0.15
2043	84	24	38	934	364	4	1,448	$ 0.15
2044	76	22	37	896	364	4	1,399	$ 0.14
2045	69	20	35	858	363	3	1,349	$ 0.14
2046	62	18	34	822	361	3	1,301	$ 0.14
2047	56	16	33	787	361	3	1,256	$ 0.14
2048	51	15	31	756	361	3	1,217	$ 0.14
2049	46	13	30	723	358	3	1,174	$ 0.13
2050	42	12	29	692	358	2	1,135	$ 0.13
2051	38	11	28	662	358	2	1,099	$ 0.13
2052	34	10	27	635	357	2	1,065	$ 0.12
2053	31	9	26	612	345	2	1,025	$ 2.25

Notes:
* Residential bill impact displayed as a differential from TP1. 1,200 kWh/month rate based on average residential price.

56. Regarding the revenue requirement analysis presented in Exhibit No. BMHB-16, please identify any assumptions, with the exception of generation additions and retirements, that are different from the revenue requirement analysis presented in witness Borsch's direct prefiled testimony in this docket. Please provide an explanation for why any assumption identified in this response is different from DEF's assumptions used in witness Borsch's direct prefiled testimony in this docket.

<u>RESPONSE</u>:

In Mr. Borsch's Exhibit BMHB-16, it is noted that the analysis reflects assumptions for a one year delay in the in-service dates of the Citrus Combined Cycle Project and the retirement date of Crystal River Units 1 and 2. The following changes are reflected in the analysis presented:

- **The ongoing capital expenditures and the Fixed O&M for the Crystal River South Units have been extended for another year.**
- **The capital costs for the Citrus Combined Cycle have been delayed by a year and escalated by 2.5%. The fixed costs have been aligned with the new in service and retirement dates.**
- **The start date for Citrus Combined Cycle's Gas Reservation Charges remains the same because the contract has already been signed, and delaying the start date will be not cost effective. The gas reservation charges have been extended by one year.**
- **Instead of the 50MW 2018 summer purchase included in the Base Case (TP1), two summer purchases were included in the CRS-Citrus delayed case, one for 150MW in year 2018 and another one for 500MW in year 2019.**

- **The assumed performance characteristics of the units remain the same in both cases, but the change in timing of the unit additions and retirements affects the production costs results, as reflected in the exhibit.**

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 20th day of August, 2014, 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 55-56 from STAFF'S FOURTH INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 55-56) in Docket No(s). 140110-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 August, 2014.

Benjamin M.H. Borsch
Benjamin M.H. Borsch

Sandra L Brice
Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 21st day of August, 2014, 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 55-56 from STAFF'S FOURTH INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 55-56) in Docket No(s). 140110-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 21st day of Aug, 2014.

Benjamin M.H. Borsch

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 078067

97

DEF's responses to Calpine's First Set of Interrogatories, Nos. 3, 4, 9

<u>See also</u>: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 97
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's First Set of Interrogatories, Nos. 3, 4, 9. See also files contained on...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	))))	DOCKET NO. 140110-EI Submitted for filing: June 17, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FIRST SET OF INTERROGATORIES (NOS. 1-9)

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-9) as follows:

GENERAL OBJECTIONS

DEF incorporates and restates its General Objections to Calpine's First Set of Interrogatories (Nos. 1-9), served on June 4, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

3. Please identify all economic, financial, and/or power system model or spreadsheet analyses used at any point by Duke for the purpose of evaluating proposals submitted in response to the RFP. Please identify the purpose of each model in analyzing the proposals in response to the RFP.

RESPONSE:

As discussed in the testimony of Benjamin Borsch, DEF used a number of models in conjunction with the evaluation of the RFP bids.

The Strategist resource optimization model was employed prior to the issuance of the RFP to establish the base case upon which the need and the NPGU option was based. During the RFP process, the options were developed so that each portfolio met the established need. No additional optimization was performed, but the only resources added to the plan in each of the scenarios reviewed were the bid, sidefill, and backfill resources. This process is described on Pages 67 – 69 of the testimony.

Detailed production cost modeling was performed using the Planning and Risk Module of the Ventyx Energy Portfolio Model (EPM). EPM uses the PROSYM calculation engine to calculate unit dispatch for the entire DEF portfolio calculating hourly values for fuels burned, emissions, variable O&M, reagent costs, and variable energy purchase costs.

Spreadsheets calculating the fixed cost items (fixed gas transportation, capital costs, fixed capacity payments to bid units, fixed O&M) were developed to identify the annual costs for these items.

For the transmission analysis, PSSE and TARA power flow software was used to do the power flow analysis using the FRCC 2013 Databank cases.

4. Please identify any assumptions used by Duke in analyzing proposals in response to the RFP regarding future changes to state and federal energy and environmental policy regarding, e.g., emission standards for carbon dioxide, sulfur dioxide, nitrogen oxides, particulates, mercury/heavy metals; control requirements related to water use and impacts; controls on liquid or solid waste; nuclear safety upgrades; and/or changes to energy efficiency and/or renewable energy standards.

RESPONSE:

DEF's assumptions generally include forecasted compliance costs for certain specific EPA regulatory programs that are either in the development stage or can reasonably expected to be forthcoming in the near future. DEF makes no attempt to speculatively forecast areas of regulation not yet under serious consideration within the applicable regulatory agencies.

To this end, DEF assumes that the EPA will promulgate additional rules regarding cooling water intake (316(b)), CO_2 emissions, renewable energy standards, and carbon combustion residuals. Air emissions of the six criteria pollutants are considered to be governed by the CAIR and Title IV programs as well as the current and proposed NAAQS standards.

- **DEF's assumptions regarding 316(b) capital costs can be found in the response to question 5.d.vii below. These assumptions were generally not material to the analysis since the Citrus project plans to install closed loop cooling and is designed to be in compliance with the current standards for new plants under 316(b). None of the competing bids were coastal facilities subject to 316(b).**
- **DEF reasonably anticipates that CO_2 emissions will have a future regulatory cost. DEF has included a price for carbon emissions which may be interpreted as an allowance price, an equivalent carbon tax, or a proxy for other changes which may be required. The values used are shown in the spreadsheet attached.**
- **DEF assumes a future federal renewable portfolio standard requiring that DEF obtain 0.5% of energy from renewable sources in 2020 increasing 0.5% per year to 2.5% in 2024. This assumption was not generally material to the analysis since DEF currently obtains approximately 3% of its energy from renewable source and expects to continue to do so through renewal and replacement of existing contracts.**
- **DEF assumes that carbon combustion residual rules will require a phasing out of wet ash handling and will continue to maintain a provision for beneficial reuse of coal ash. DEF did not include a specific cost for compliance with this rule since DEF currently sells all of its ash and gypsum for beneficial reuse and anticipates being able to do so in the future.**
- **DEF has assumed allowance prices for NOx and SO_2 to achieve compliance with CAIR. These values are given in the response to question 5. At the time this analysis was performed, the Supreme Court ruling reinstating CSAPR had not been made. The NPGU is anticipated to comply with the current and proposed NAAQS. DEF also assumed that there would be no NAAQS related impacts on any of the bidding facilities. DEF assumed emissions rates for NOx and SO_2 from bidding facilities as specified in Schedule 6 of each bid.**

None of the above assumptions with the exception of the CO_2 price assumption was considered to be material to the analysis. To examine the impact of the CO_2 price assumption on the results, DEF performed a no-carbon price sensitivity. This is discussed on pages 80 – 86 of the Need Study (Exhibit BMHB-1).

9. In evaluating self-build options, how (if at all) does Duke account for the potential for capital cost overruns?

<u>RESPONSE:</u>

DEF did not prepare cost overrun scenarios for use in evaluating the cumulative present value revenue requirements for the Citrus self-build option because under Rule 25-22.082, F.A.C, costs in addition to those identified in the need determination proceeding are not recoverable unless DEF can demonstrate that such costs were prudently incurred and due to extraordinary circumstances. Accordingly, DEF understands that it will be expected to complete the project at the estimated cost.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 13th day of June, 2014, 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) 1 through 9 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-9) in Docket No(s). 140110-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 13th day of June, 2014.

Benjamin M.H. Borsch

Sandra L Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

98

DEF's responses to Calpine's Fourth Set of Interrogatories, Nos. 14-15 & DEF's supplemental response to Calpine's Fourth Set of Interrogatories, No. 14

<u>See also</u>: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 98
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's Fourth Set of Interrogatories, Nos. 14-15 & DEF's Supplemental response...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI SERVED: July 3, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES (NOS. 14-15) TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 14-15) to Duke Energy Florida, Inc. as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 14-15), served on June 27, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

14. Refer to the Direct Testimony of Benjamin M.H. Borsch, Docket 140110-EI. To the extent not addressed in the responses to Interrogatories No. 3 and No. 4 served on May 30, 2014, please provide information for generic combustion turbine units as back-fill and side-fill units in Strategist that is comparable to the Undesignated CC cost schedule in BMHB-2, Schedule 9, Page 58 of 76. Please explain how these costs differ, if at all, from the generic costs included in BMHB-5.

RESPONSE:

DEF presumes in this question that Calpine is referring to a comparison of the generic combined cycle units in sidefill and back fill service compared to the Undesignated CC found on Schedule 9 of the Ten-Year Site Plan (incorporated as Exhibit BMHB-2). The side fill combined cycle units were identical to those presented in that Schedule. The backfill units use the same capital and fixed cost assumptions (escalated to the in-service dates), but have been scaled to 450MW in size on a $/kw basis to better align with the sizes of the bids considered in the evaluation. The backfill units also have a slightly lower heat rate (Baseload summer heat rate of 6,508 Btu/kw HHV for the back fill vs. 6,711 for the side fill unit) on the presumption that future units will be more efficient than the current generation.

15. Please refer to the Direct Testimony of Alan Taylor, Docket 140110-EI, exhibit AST-1, page 23 of 26. Mr. Taylor states with respect to generic resources that "CC resources [are] higher ranked and more cost-effective than the CT resources. DEF and Sedway Consulting discussed this and noted that if a portfolio with side-fill CCs was selected as the best portfolio, that would invariably trigger another RFP under the Florida Bid Rule. Using the side-fill CTs would not have that result. Ultimately, Sedway Consulting decided to use the best side-fill resources to give outside proposals the most cost-effective portfolio partners..."

Please describe the extent to which DEF considered the combination CC and CT resources for back-fill and side-fill units in its Strategist Evaluations. In particular, if side-fill CTs are more expensive than side-fill CCs from a ratepayer perspective, please explain why Bids A, G, and C1 in BMHB-12 were each independently modeled in Strategist as a combination of generic CC and CT units.

RESPONSE:

In each of the Portfolios constructed for evaluation, DEF selected generic units which would result in a Portfolio of approximately 1640 MW which could be evaluated against the NPGU in a direct comparison. In the Portfolios cited, the bids provided between 388 and 508 MW. In order to match these Portfolios with the NPGU capacity, a combination of generic CC and CT units was added to the portfolio. Had DEF not utilized some CT units in these combinations, the subject Portfolios would have been of capacities not directly comparable to the NPGU.

Mr. Taylor's statement specifically refers to discussions he held with the Company after the 2018 RFP proposals were received to address the fact that none of the proposals individually or collectively met DEF's reliability need in 2018. Rather than reject the proposals for failure to comply with the 2018 RFP, which DEF reasonably could have done, the Company and Mr. Taylor discussed the evaluation of the 2018 RFP proposals in combination, individually or collectively, with other, undeveloped generic Company power plants to see if these resource combination scenarios were quantitatively and qualitatively cost-effective supply side alternatives to the Citrus County Combined Cycle Power Plant. To this end, DEF and Sedway considered pairing the bids with Portfolios including only CT units in the 2018 timeframe, reflecting the fact that if a CC unit were used, there would be a need for a new RFP and may result in a schedule constraint, additional costs, and additional risks in building a CC unit in that timeframe. Notwithstanding the potential schedule constraint, additional costs and additional risks, DEF and Sedway decided to evaluate Portfolios including the generic combined cycles and then consider how to address the schedule and other qualitative issues associated with the generic combined cycles if those Portfolios were economically competitive.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of July, 2014, 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) 14 and 15 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 14-15) in Docket No. 140110-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Benjamin M.H. Borsch

Sandra L. Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI SERVED: July 8, 2014

DUKE ENERGY FLORIDA, INC.'S *SUPPLEMENTAL* RESPONSE TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES (NOS. 14-15) TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") provides this supplemental response to Interrogatory Number 14 of Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 14-15) to Duke Energy Florida, Inc. and states as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 14-15), served on June 27, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

14. Refer to the Direct Testimony of Benjamin M.H. Borsch, Docket 140110-EI. To the extent not addressed in the responses to Interrogatories No. 3 and No. 4 served on May 30, 2014, please provide information for generic combustion turbine units as back-fill and side-fill units in Strategist that is comparable to the Undesignated CC cost schedule in BMHB-2, Schedule 9, Page 58 of 76. Please explain how these costs differ, if at all, from the generic costs included in BMHB-5.

SUPPLEMENTAL RESPONSE:

Based on clarification from Calpine on this request, DEF understands that Calpine is requesting information on the combustion turbine (CT) units used as side-fill units in the analysis, provided in the format that DEF normally provides unit details in the annual 10 year Site Plan filings, Schedule 9. These specific units were not included in the 2014 Ten Year Site Plan, but DEF is providing the requested information in that format in the document attached in Bates range 14BGBRA-CALPINE4-14-000001 through 14BGBRA-CALPINE4-14-000004.

The basis for the generic CT costs in BMHB-5 is a Brownfield CT with a construction start date of 1/2014 and in-service date of 6/2016. The bases for the generic CT costs used for side-fill requested in this Interrogatory were Brownfield and Greenfield CT's with construction start dates of 1/2016 and 5/2016 and in-service dates of 5/2018 and 11/2018.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 25th day of July, 2014, 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 number 14 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 114-15) in Docket No. 140110-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 25th day of July, 2014.

Benjamin M.H. Borsch

Notary Public
State of Florida, at Large

My Commission Expires:
3/8/18

SANDRA C. COP
Notary Public - State of Florida
My Comm. Expires Mar 8, 201
Commission # FF 070867

99

DEF's responses to OPC's First Set of Interrogatories, Nos. 1-3, 9, 11-12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 99
PARTY: STAFF
DESCRIPTION: DEF's responses to OPC's First Set of Interrogatories, Nos. 1-3, 9, 11-12.
[Bates Nos. 00106-00121]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI Served: July 1, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO CITIZENS' FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-12)

Duke Energy Florida, Inc. ("DEF") responds to Citizens' First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-12) as follows:

REDACTED

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Citizens' First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-12), served on June 23, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

1. This interrogatory relates to the statement in paragraph 5 on page 3 of the Company's Petition of Determination of Need (PDN) that "Economic conditions now support customer and energy demand growth and that is what we (sic) DEF is now experiencing in its service area." Please provide a comparison of the Company's forecasts with the temperature corrected actual and actual recorded peak demands for both summer and winter seasons in the following tabular format:

	Summer (or Winter) Peak Demand in MW						
Year	Forecast Peak Demand In 2008	Forecast Peak Demand In 2009	Forecast Peak Demand In 2010	Forecast Peak Demand In 2011	Forecast Peak Demand In 2012	Temperature Corrected Actual Peak Demand	Actual Recorded Peak Demand
2009		NA	NA	NA	NA		

2010			NA	NA	NA		
2011				NA	NA		
2012					NA		
2013							

<u>RESPONSE</u>:

Please see the Table Q1 below:

	DEF System Winter Peak Demand in MW						
Year	Forecast Peak Demand In 2008	Forecast Peak Demand In 2009	Forecast Peak Demand In 2010	Forecast Peak Demand In 2011	Forecast Peak Demand In 2012	Temperature Corrected Actual Peak Demand	Actual Recorded Peak Demand
2009	11327	NA	NA	NA	NA	11396	11313
2010	11400	10972	NA	NA	NA	11540	12860
2011	11562	10878	10713	NA	NA	10121	10534
2012	11950	11218	10833	10551	NA	8640	8722
2013	12289	11508	10994	10363	10128	8968	8032

	DEF System Summer Peak Demand in MW						
Year	Forecast Peak Demand In 2008	Forecast Peak Demand In 2009	Forecast Peak Demand In 2010	Forecast Peak Demand In 2011	Forecast Peak Demand In 2012	Temperature Corrected Actual Peak Demand	Actual Recorded Peak Demand
2009	10242	NA	NA	NA	NA	9919	10261
2010	10220	9715	NA	NA	NA	9413	9600
2011	10358	9571	9436	NA	NA	9111	9277
2012	10713	9841	9610	9629	NA	9140	8850
2013	10983	10025	9761	9415	9669	8931	8776

2. This interrogatory relates to the statement in paragraph 13 on page 7 of the Company's PDN that location of the Citrus combined cycle plant near CREC allows the "...Company to use existing infrastructure at the CREC to support the proposed plant." Please provide the following:

a. A comprehensive list of each element of the existing infrastructure that the Company would use for the Citrus plant;

RESPONSE:

- **CR3 intake structure for cooling water supply**
- **CREC discharge canal for cooling tower blowdown**
- **230kV and 500kV transmission facilities for plant interconnection**
- **Water wells for process water supply**
- **Rail and roads for delivery of equipment and materials**

b. For each element listed in item (a) above that requires the removal of either CR 1, CR2, or both units from service in order for Citrus plant to use the existing infrastructure, please provide a detailed explanation identifying each Crystal River unit which must be removed from service, the reasons why removal would be necessary, and the amount of time prior to commercial operation of Citrus during which the unit(s) would be incapable of delivering power to serve the Company's load.

RESPONSE:

With regard to 230kV transmission capacity, during commissioning of the first 2X1 CC power block beginning in early 2018, the combined output of CR1, CR2 and the 2X1 CC power block would be limited to approximately 900 MW. After commercial operation of the first 2X1 power block, planned for May 2018, CR1 and CR2 would be retired due to the 230kV transmission capacity limitation.

With regard to water wells upon commercial operation of the first 2X1 CC power block, CR1 and CR2 would be retired and the water wells dedicated to the 2X1 CC power block.

The other items above do not apply to the question 2b.

3. The interrogatory relates to the statement in paragraph 22 on page 11 of the Company's PDN that the Company cannot continue "...operation of CR 1 and CR 2 beyond 2018 without substantial investment in new environmental compliance equipment and measures for CR 1 and CR 2," Please provide the following:

a. A detailed enumeration of each "investment in new environmental compliance equipment and measures for CR 1 and CR 2" necessary for continued operation of CR 1 and CR 2 through June 2019 and a quantification and description of the cost associated with each such investment in compliance equipment and measures;

b. A detailed enumeration of each "investment in new environmental compliance equipment and measures for CR 1 and CR 2" necessary for continued operation of one CR unit (either CR 1 or CR 2) interconnected to the 500 kV transmission system from the end of June 2019 through the period of summer peak demand for in 2019 and a quantification and description of the cost associated with each such investment in compliance equipment and measures; and

c. A detailed enumeration of each "investment in new environmental compliance equipment and measures for CR 1 and CR 2" necessary for continued operation of CR 1 and CR 2 through the end of calendar year 2020 and a quantification and description of the cost associated with each such investment in compliance equipment and measures.

RESPONSE:

Provisions in the current permit for CR 1 & 2 require that the units cease to operate on coal, on or before 12/31/2020. These restrictions were incorporated into the CR 1 & 2 permit during the EPA's review of Florida's proposed Regional Haze State Implementation Plan (SIP) [re: EPA–R04–OAR–2010–0935; FRL– 9900–31–Region 4; Federal Register Vol. 78, No. 168; August 29, 2013; Approval and Promulgation of Air

Quality Implementation Plans; State of Florida; Regional Haze State Implementation Plan]. In the course of DEF's compliance planning review for Regional Haze and CAMR/MATS, the Company considered the installation of significant new emission controls systems (e.g. dry scrubbers, bag houses, SCR's) that DEP would have required to be operational on or before 1/1/2018. The Company also considered less extensive MATS compliance options suitable only for limited continued operations, which were ultimately incorporated into DEF's proposed compliance plan.

Given the complexity of the MATS compliance requirements, the age and condition of the units and the potential for imposition of additional compliance requirements, the Company's plan for "limited continued" operations was established focusing on extending operations through mid-2018, or until the planned replacement generation would be available to reliably serve the load. DEF's view is that extending CR 1&2 operation further, perhaps into 2019, or potentially 2020, poses increased risks from both operational reliability and compliance perspectives. The primary area of concern is increasing the length of time that the Company would continue operating with the MATS driven operational dependency between the two older units and CR 4&5 as a result of the site emissions averaging approach. There is a risk that an extended outage event on one or both of these units could result in a need to curtail operations at CR 1&2, further restricting power supply and limiting the ability of these units to provide much needed support to the grid. While this risk is present in the current operating plan from mid-2016 to 2018, the Company's efforts to move forward with construction of the replacement generation resources in an expeditious manner are intended to limit that risk to the extent possible, while preserving the benefits of the current generation and compliance plans for customers.

In addition to the operational reliability considerations, the Company also recognizes the potential for significant impacts associated with recently implemented regulations such as the 1-hour SO_2 NAAQS, 316(b) and other emerging regulations. It is anticipated that 2018/19 could be a pivotal period for the implementation of these regulations, and those considerations have motivated the Company to plan to move through these transitions as expeditiously as reasonably possible.

In response to (a) and (c), the studies performed did not specifically address additional investment in new environmental compliance equipment and measures for continued operation of CR 1&2 through June 2019 (or through the end of 2020, as referenced in part c. of this interrogatory) because that was not contemplated as part of the plan. Indeed, for example, for compliance issues related to 1-hour SO_2 NAAQS in that timeframe, the likely required compliance approach would be retirement of CR 1&2, as contemplated in DEF's plan. For compliance measures related to 316(b), early DEF studies suggested that mitigation project spending would likely begin in 2019, and that the estimated cost of compliance projects would be roughly $260M. There would of course be additional investment in 2019 and 2020 if CR1 and CR2 commercial operation was extended because at a minimum DEF would have to incur the incremental costs associated with its MATS compliance plan for CR1 and CR2 through mid-2018 in years 2019 and 2020. For the reasons provided, however, extending that MATS compliance plan beyond mid-2018 is,

considering all quantitative and qualitative factors, not a reliable, cost-effective plan for DEF's customers.

9. With respect to the testimony of Mark E. Landseidel on page 7 at Line 9 through Line 11, please provide the following:

a. Clarify whether peaking capacity discussed in the testimony is in addition to 820 MW power block rating (i.e., the total summer output with duct firing is 920 MW);

RESPONSE:

The duct burning capacity is included in the 820 MW power block rating.

b. Identify the operational situation(s) that results in 50 MW vs 100 MW of peaking capacity (e.g., 2x1 configuration results in 100 MW vs 1x1 (one CT out of service) configuration resulting in 50 MW);

RESPONSE:

The 50MW to 100MW is the estimated range of duct burning capacity that will supplement the unfired output during summer to provide the 820 MW power block output in a 2x1 configuration.

For example on a 90F summer day the unfired output will be 737MW and with 83 MW of duct burning the power block output will be 820 MW.

c. A detailed description of the cost effectiveness of duct firing to achieve 50 MW of peaking capacity;

RESPONSE:

The installed cost of the duct burning capacity is estimated to be \$300 to \$400 / kW. This compares favorably to the installed cost of a peaking plant using F class combustion turbines of \$600 to \$700 / kW. The duct burning heat rate is also better than F class combustion turbines operating in simple cycle.

d. A detailed description of the cost effectiveness of duct firing to achieve 100 MW of peaking capacity; and

RESPONSE:

See response to 9(c) above.

e. A detailed description of any limitation as to the length of time associated with duct firing to achieve either the 50 MW or 100 MW of peaking capacity.

RESPONSE:

The estimated ramp rate is 10 MW per minute (5 and 10 minutes respectively).

11. With respect to the testimony of Jeffery Patton on page 6 at Line 6 through Line 8, please provide the following:

a. A detailed description (including citations to contract provisions) of the contractual consequences of DEF beginning to take delivery of gas on October 1, 2018 rather than on October 1, 2017 (e.g., a delay in the start of payments consistent with a delay in the contract start date due to DEF delaying the commercial operation date of the first power block); and

RESPONSE:

DEF is of the opinion that any delay in our in-service date outside of the defined conditions in our contract would result in a requirement to renegotiate the contract, which in turn would result in a higher reservation rate for transportation service. The pipeline owner's goal in such a negotiation would be to obtain equal total value in the new contract as in the current one. DEF's belief is that the best proxy for this would be to assume that DEF would be required to pay for the transportation service per the current contract in-service date of October 1, 2017 as scheduled regardless of DEF's first year gas usage.

b. A detailed description (including citation to contract provisions) of the contractual consequences of Sabal Trail failing to be able to deliver gas on October 1, 2017 (e.g., performance penalties associated with a delay due to Sabal Trail).

REDACTED

RESPONSE:

[redacted]

Florida Power & Light Company ("FPL") is a Project Foundation Shipper on Sabal Trail and FPL's Petition for Prudence Determination Regarding New Pipeline System (FPSC Docket No. 1301198-EI filed July 26, 2013) contains Exhibit HCS-2 which is the executed Precedent Agreement ("PA") between FPL and Sabal Trail. Pages 23, 24, and 35 of Exhibit HCS-2 (PA - Section 10.1 and Attachment 1) contain the details of the contract provisions that provides the mechanism for economic compensation made available to FPL in the event of a delay due to Sabal Trail. These provisions (see attachment TBD) provides FPL (at the election of Sabal Trail) either a rate reduction or delay damages should the project be delayed thirty (30) days or greater from the expected commencement date which for FPL is May 1, 2017. [redacted]

12. With respect to the testimony of Jeffery Patton on page 10 at Lines 13 through 23 and page 11 at Lines 1 through 6, please enumerate and quantify any additional costs associated with utilizing the firm natural gas transportation alternatives.

REDACTED

RESPONSE:

DEF and Sabal Trail plan an additional interconnect agreement between Sabal Trail and FGT in Citrus County, Florida. This interconnect is currently estimated at approximately [redacted]. Under the proposed reimbursable agreement between DEF and Sabal Trail, DEF would reimburse Sabal Trail for the expenses incurred for these facilities. The reimbursable agreement and the Sabal Trail / FGT interconnect in Citrus County will be completed prior to the commercial operation date of the Citrus County Combined Cycle Plant. This interconnect will provide DEF the ability to utilize supply and existing agreements on FGT. DEF will not be contracting for additional firm gas transportation on FGT to utilize the firm natural gas alternatives provided by the interconnect between FGT and Sabal Trail in Citrus County, Florida.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of ~~June~~ July 2014, 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) 1, 2b, 3a through 3c, 4a, 4b, 5, 6, 7a through 7f, 8a through 8d from CITIZENS' FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-12) in Docket No(s). 140110-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

35427796.1

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 26th day of June, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jeffrey Patton, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 11a, 11b and 12 from CITIZENS' FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-12) in Docket No(s). 140110-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 26th day of June, 2014.

RITA G KALE
NOTARY PUBLIC
CATAWBA CO., NORTH CAROLINA

Jeff Patton
Jeffrey Patton

Rita G Kale
Notary Public
State of North Carolina, at Large

My Commission Expires: 6/17/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 26th day of June, 2014, 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 answers to interrogatory number(s) 2a, 9a through 9e, 10a and 10b from CITIZENS' FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-12) in Docket No(s). 140110-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 26th day of June, 2014.

Mark E. Landseidel

Notary Public
State of ~~Florida, at Large~~ North Carolina

My Commission Expires:
October 20, 2018

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DEF's responses to Staff's First Production of Documents, Nos. 2, 3, 5 (Confidential FPSC Document No. 03725-14)

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 100
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's First Production of Documents, Nos. 2, 3, 5 (Confidential FPSC Document N...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI DATED: July 15, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO DUKE ENERGY FLORIDA, INC. (NOS. 1-6)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Request for Production of Documents to Duke Energy Florida, Inc. (Nos. 1-6) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's First Request for Production of Documents Nos. 1-6, served on July 7, 2014, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

2. Referring to page 46, lines 3-5, of witness B. Borsch's direct testimony, please provide a copy of the transcript of the pre-issuance meeting.

RESPONSE:

Please see documents attached in Bates range 14BGBRA-STAFFPOD1-2-000001 through 14BGBRA-STAFFPOD1-2-000026.

3. Referring to page 46, lines 3-5, of witness B. Borsch's direct testimony, please provide a copy of the pre-issuance presentation.

<u>RESPONSE</u>:

Please see documents attached in Bates range 14BGBRA-STAFFPOD1-3-000001 through 14BGBRA-STAFFPOD1-3-000021.

5. Please provide the work papers/spreadsheets, with the formulas intact, showing the calculation of the Debt Equivalence Costs shown on Page 21 of 26 of Exhibit AST-1 of the Independent Evaluation Report submitted by Alan S. Taylor.

<u>RESPONSE</u>:

Please see documents produced in Bates range 14BGBRA-STAFFPOD1-5-000001 through 14BGBRA-STAFFPOD1-5-000013. These documents are confidential and subject to DEF's Sixth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

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DEF's responses to Staff's First Set of Interrogatories, Nos. 1-29, 30 (revised), 31-55

See also: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 101
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's First Set of Interrogatories, Nos. 1-29, 30 (revised), 31-55. See also fi...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of cost effective generation alternative to meet need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI DATED: July 15, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-55)

Duke Energy Florida, Inc. ("DEF") responds to Staff of the Florida Public Service Commission ("Staff") First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-55) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's First Set of Interrogatories (Nos. 1-55), served on July 7, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

The following questions refer to the direct testimony and exhibits of Benjamin M.H. Borsch.

1. Referring to page 10, lines 2-5, when did the planned retirement of the discussed combustion turbine generation plants first appear in the Company's Ten-Year Site Plan?

RESPONSE:

The planned retirement of Avon Park, Rio Pinar and Turner P1&P2 first appeared in the 2008 Ten Year Site Plan.

2. On page 10 the witness states that the less efficient combustion turbines that are planned for retirement "are increasingly more costly to operate and maintain."

a. Has DEF evaluated the cost-effectiveness of keeping the discussed combustion turbines in-service?

RESPONSE:

The Company has not recently performed an evaluation of cost-effectiveness of keeping these units in service. These units were originally identified during the 2008 planning cycle for retirement in 2016 based on the age of the equipment and the limited availability of replacement parts.

b. If yes, please summarize the results of DEF's evaluation.

RESPONSE:

Not applicable.

c. Please complete the table below summarizing the O&M costs of the combustions turbines that are planned for retirement.

Year	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)
1990		
1991		
1992		
1993		
1994		
1995		
1996		
1997		
1998		
1999		
2000		
2001		
2002		
2003		

2004		
2005		
2006		
2007		
2008		
2009		
2010		
2011		
2012		
2013		
2014		

RESPONSE:

The O&M cost history from 2008 - 2013 for each of the stations requested is provided below. The Company uses the fixed and variable O&M categories for modeling and forecasting, but typically does not record actual expenses in these categories, so the historic O&M totals have been provided below. The expense history starting in 2008 was readily accessible from company record systems. Historical information prior to 2008 may be accessed manually in the Company's FERC Form 1 filings, if this information is needed.

Station Total O&M Expenses By Year

Year	Avon Park	Rio Pinar	*Turner
2008	$ 676,682	$ 69,913	$ 2,742,536
2009	$ 660,569	$ 86,260	$ 727,511
2010	$ 506,145	$ 87,668	$ 1,217,578
2011	$ 536,569	$ 65,586	$ 647,677
2012	$ 568,075	$ 51,527	$ 724,038
2013	$ 293,897	$ 82,856	$ 870,613

**Tuner = Includes all 4 CT units at the site*

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3. On page 10 the witness states that DEF 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."

a. Has DEF evaluated the cost-effectiveness of keeping the discussed Suwannee power plants in-service?

RESPONSE:

These units were originally identified during the 2008 planning cycle for retirement in 2013 based on the age of the equipment and the limited cost effectiveness of operating these older, smaller steam units. The Company has not recently performed an evaluation of the cost-effectiveness of keeping these units in service. The timing of the Suwannee steam unit retirements has shifted in some of the subsequent planning cycles as the Company's plans for generation additions have changed. As discussed in the response to Interrogatory 4, the benefits of retiring the units in 2016 were recently evaluated and supported by reductions in costs associated with construction of transmission facilities to support the new peaking units at the site.

b. Please complete the table below summarizing the O&M costs of the oil- and gas fired steam generation plants at the Company's Suwannee power plant site.

Year	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)
1990		
1991		
1992		
1993		
1994		
1995		
1996		
1997		
1998		
1999		
2000		
2001		
2002		
2003		
2004		
2005		
2006		

2007		
2008		
2009		
2010		
2011		
2012		
2013		
2014		

RESPONSE:

The O&M cost history from 2008 - 2013 for each of the stations requested is provided below. The Company uses the fixed and variable O&M categories for modeling and forecasting, but typically does not record actual expenses in these categories, so the historic O&M totals have been provided below. The expense history starting in 2008 was readily accessible from company record systems. Historical information prior to 2008 may be accessed manually in the Company's FERC Form 1 filings, if this information is needed.

Station Total O&M Expenses By Year

Year	Suwannee
2013	$ 5,295,690
2012	$ 4,825,321
2011	$ 3,913,150
2010	$ 3,700,077
2009	$ 3,402,170
2008	$ 4,314,625

4. On page 10 the witness states that DEF will retire the Suwannee power plants "in 2016 to reduce the cost of the transmission upgrades needed for installation of the proposed peakers." Please quantify the transmission upgrade cost reduction associated with retiring the units in 2016.

RESPONSE:

As explained in Mr. Borsch's testimony referring to the existing Suwannee steam units, "These units were originally 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." DEF transmission analysis showed that retiring the steam units at the time of commercial operation of the peakers in 2016 would avoid the need for significant transmission upgrades, reducing the transmission upgrade costs from approximately $70 million to the forecast $15.7 million.

5. On page 24 the witness states that "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." Please provide any documentation or evidence supporting this statement.

RESPONSE:

Over the years in which DEF has administered dispatchable demand-side resources, DEF has seen several instances in which customers have left such programs in large numbers. First, in several summers in which Florida has experienced unusually high temperatures, DEF has had to move beyond interrupting customer pool pumps and hot water heaters and has had to use interruptions to customer air conditioners. While this is generally an uncommon occurrence for long durations, customers have reacted very negatively to extended air conditioner interruptions and have left these dispatchable programs in large numbers during these periods. Additionally, between 2006 and 2012, Florida had instances of extreme cold weather events which led to DEF having to interrupt electrical heating service for customers including several school systems. During these times, students at schools were sent home and media coverage resulted from the events. This led to some of the impacted school systems withdrawing from such interruptible programs. These examples demonstrate the logical concept that customers will have little tolerance for extended interruptions to cooling and heating services in times of extreme weather, which, of course, are the times in which DEF will need generation reserves the most.

6. On page 27, the witness states that DEF has a "Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects." When did DEF first issue its RFR?

RESPONSE:

DEF first issued its RFR on July 19, 2007.

7. Please identify and discuss all renewable contracts, since 2005, which DEF has signed but did not achieve commercial operation. Please identify the reason that the renewable generator did not achieve commercial operation.

<u>RESPONSE</u>:

Please refer to the table provided in the attachment entitled "Table 140111 Staff 1st ROG 7.docx"attached in Bates range 14LGBRA-STAFFROG1-7-000001 through 14LGBRA-STAFFROG1-7-000003. This document is confidential and subject to DEF's Tenth Notice of Intent filed contemporaneously with the service of this document.

8. On page 30, the witness states that DEF's generation 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. Please explain what is considered in consumable costs.

RESPONSE:

Consumable items that are typically included in the evaluation include sorbents and reagents which may include, for example, limestone, hydrated lime and ammonia.

9. Referring to page 32, lines 15-23, and page 33, lines 1-17.

a. Did DEF retain an independent monitor to ensure that the described solicitation process was fair and impartial and that the solicitation documents were clear and fair?

RESPONSE:

No, please see DEF's response to section (b) below.

b. If no, why not?

RESPONSE:

The request for proposal for DEF's generation needs in 2018 is governed by the Florida Power Plant Siting Act ("PPSA") and that solicitation has proscriptive and complex rules and procedures that must be followed to have a compliant bid event. Because of these facts, DEF retained an independent monitor to help ensure compliance. Unlike the solicitation for DEF's 2018 generation needs, however, there are no formal rules or requirements that govern solicitations for needs that are not covered by the PPSA. In fact, there is no explicit requirement that DEF conduct any solicitation at all for needs not covered by the PPSA. Accordingly, DEF did not believe that an independent monitor was needed for a non-PPSA event. Notwithstanding this fact, however, DEF conducted a robust solicitation of alternative power purchase agreements and plant acquisitions for its generation needs prior to 2018.

c. If yes, please identify the independent monitor.

RESPONSE:

N/A.

d. If yes, please provide any results and/or conclusions produced by the independent monitor.

RESPONSE:

N/A.

10. On page 41, the witness states that DEF quantified construction cost sensitivity around the Suwannee and Hines projects, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks.

a. Please describe in detail how DEF developed the costs associated with these risks.

<u>**RESPONSE**</u>:

Exhibits BMHB-8 and BMHB-9 in Mr. Borsch's testimony address the results of the initial detailed economic analysis. Exhibit BMHB-8 lists the results of the evaluations comparing the each of the alternatives with the base case. The results table details the differentials for each of the component areas of cost evaluated (Capital Cost, Fuel, Emissions and so on) for the alternative cases versus the base case. Exhibit BMHB-9 shows the results of the cost risk sensitivity analysis that addressed the Company's self build options and the acquisition and power purchase options listed in exhibit BMHB-8. The reference values for each case, depicted as yellow diamonds in the exhibit BMHB-9 chart, were based on the "Total" values listed in the table presented in exhibit BMHB-8. The cost risk sensitivity analysis addressed appropriate ranges of cost variation for each of the alternatives considered. The results of the ranges of potential variations in cost effectiveness were depicted for each alternative as the blue bars on the chart.

At the time the initial detail economic analysis was performed, the cost risk sensitivity analysis addressed the key areas of cost uncertainty that had been identified by the analysis team for each of the alternatives. Some of the range values were developed based on underlying studies and analysis, and some of the range values were determined based on input from Company subject matter experts. The details of the calculations and analysis supporting exhibit BMHB-9 were previously provided in response to NRG's 1st Interrogatories #28. A few examples of the approaches used to establish the sensitivity ranges are provided.

***<u>Construction Cost Sensitivities</u>*: At the time this analysis was performed, the Suwannee simple cycle project estimate was being finalized and the project team provide a reasonable cost confidence range of -10% to +25% to use for this sensitivity analysis. The current cost estimate is still close to the original reference value. For the Hines Chiller Project, the project team had already requested that the economic analysis be performed at the top end of the project cost range, so the analysis considered a potential cost roughly 15% below the top of the range for the lower end of the sensitivity. These ranges were reasonable based on the information available at the time. As the**

projects have progressed, the range of uncertainty has been reduced and the costs estimates are still close to the reference values assumed.

***Gas Transportation Contract Risk Sensitivities*: The gas fixed transportation (FT) contract assumptions were based on the best information available at the time of the analysis, but there were key uncertainties under review at that time and the sensitivity ranges were developed with support from the Company's fuels experts to reflect the FT cost ranges being evaluated. These sensitivity range assumptions are included for each alternative, where appropriate, supported by input from Duke Energy's fuels experts. A couple of specific sensitivity assumptions are discussed to illustrate the process.**

> ***Suwannee Simple Cycle Project*: In the case of the Suwannee Simple Cycle Project, the Company assumed that the current plant infrastructure and FT portfolio would support the project without adding additional FT, but the analysis team requested verification of that fact and included a sensitivity in the review reflecting additional FT that would result in a unfavorable CPVRR shift of $125M, included in the spreadsheet model as a "High Diff" sensitivity range item listed under "Fixed Costs: FT". That value represented the large portion of the uncertainty depicted for the self-build alternative in the chart. Note that since the initial analysis, the fuels team has confirmed that no additional FT will be required for the project, so that sensitivity is moot.**
>
> ***Acquisition 1*: In the initial analysis of the Acquisition 1 alternative, the planning team had assumed that DEF would use the entity's existing FT contracts, subject to further review of the contracts and assessment of DEF's portfolio FT needs. While that review was underway, the Fuels team recommended that the sensitivity reflect the potential for an additional 30,000 DTh/day resulting in a CPVRR impact of an additional $200M over the study period. These values were included in the sensitivity analysis supporting exhibit BMHB-9, listed as adjustments to the "Fixed Costs: FT" values. The differential value in the reference case was ($162M), so the "Low Diff" sensitivity assumed no change, so the value remained ($162M). In the "High Diff" case, the $200M was added, resulting in the adjusted value of ($361M). Since that time, the Fuel team's analysis was completed and it was confirmed that portions of the existing FT contracts would not be eligible for renewal, and it has been confirmed that if DEF purchased the facility, an additional 30,000 DTh/day of FT would be required to meet DEF's reliability planning guidelines as a result of the physical location of the facility on the Florida gas supply network.**

***Plant Condition and Maintenance Risks*:** **For the plant acquisitions being considered, the reference case studies included the indicative purchase prices offered, but did not include any allowances for additional costs associated with plant condition and maintenance program costs. The planning team needed to include an initial reasonable range for each acquisition alternative representing the costs typically incurred after an existing facility acquisition for initial repairs and reconditioning as well as the changes needed to integrate the facility into the utility's equipment maintenance programs including, for example, OEM long term maintenance agreements for combustion turbine maintenance. As the evaluation process was progressing, the Company assembled a team that prepared to conduct due diligence reviews of the short listed facilities, and this team was asked to provide reasonable ranges used for use in the sensitivity study based on their general knowledge of the facilities. It was assumed that these cost estimates would be refined during detailed due diligence efforts if the inquiry progressed to that phase. These figures were included in the "Capital: Plant Updates" category in the spreadsheet model.**

***Transmission Cost Risks*:** **Transmission cost risks were assessed for several of the facility acquisition and purchased power alternatives being considered. The assumptions used in the initial detailed analysis were provided by DEF's transmission experts based on initial screening analysis and any information that was available based on ongoing studies by the utilities and the FRCC. DEF's transmission planning experts provided support in establishing the cost sensitivity ranges appropriate for each alternative being considered. The process used to evaluate Acquisition 2 illustrates the approach used for addressing transmission cost risk sensitivity. In the initial studies of the acquisition of this facility, the Company's planning and transmission teams reviewed options for wheeling through existing interconnections and a conceptual alternative to direct connect the facility to DEF's system. The review revealed that it would be more cost effective to direct connect, so the baseline assumption chosen reflected the capital cost for conceptual transmission projects to direct connect to the facility, subject to further study, if appropriate. The reference value of $258M for transmission in the sensitivity spreadsheet model reflects the CPVRR impacts of those assumed capital costs. The "High Diff" value of $290M and the "Low Diff" value of $175M reflect the range that the transmission interconnect costs could be marginally higher, or potentially significantly lower.**

b. Are the risks for each option independent of each other (i.e. could Base (Self) risks be high and Acquisition 1 risks below)?

RESPONSE:

The cost risk sensitivity analysis approach used was appropriate for the intended purpose of a screening assessment of alternatives. The model does provide a static assessment of the sensitivity ranges, and the risks are independent, as suggested. One adjustment that was used in analysis was the use of the "High" and "Low" factors applied to the calculations of the "High Diff" and "Low Diff" range results to reflect the fact that it would be unlikely that all of the sensitivity drivers would be coincidently high and/or low together. Adjustment factors of 80% were used to develop the result charts and tables for this analysis, as depicted in BMHB-9. The planning team members and management representatives who reviewed the results of this analysis also had reasonable knowledge and awareness of the drivers of these sensitivities and were able to apply reasonable judgment in their review and formulation of recommendations for selection of alternatives to continue to evaluate in further detail.

11. On page 46, the witness indicates that the Company would incur costs in order to seek Federal Energy Regulatory Commission (FERC) approval for generation facility acquisitions. How much does DEF estimate seeking FERC approval would cost? Please explain your answer.

<u>**RESPONSE**</u>:

The costs of obtaining FERC approval can vary significantly, depending on whether there are protests, interventions, any FERC Commission or staff requests for additional information, etc. At a minimum, there will be costs for outside FERC counsel and expert consultants, both of which likely would be necessary to obtain FERC approval. DEF did not attempt to estimate the overall costs of obtaining FERC approval as part of its analysis of the most cost-effective option to meet DEF's need prior to 2018 because this was not a determinative factor in that analysis. However, while DEF has not filed any applications with FERC for a generation facility acquisition under the circumstances such as exist here, DEF expects that the cost of outside FERC counsel and expert consultants, among other costs of a FERC proceeding for approval of a generation facility acquisition, will be at least $1 million.

12. On page 47, the witness claims that the FERC would take a minimum of six months to reach a decision regarding approval of the generation acquisition.

c. Can the company provide support for this claim?

RESPONSE:

a. **See 18 CFR §33.11. http://www.ecfr.gov/cgi-bin/text-idx?SID=315f020891d2f76730cb2a6e8cbb90f5&node=18:1.0.1.2.21.0.23.10&rgn=div8**

§ 33.11 Commission procedures for the consideration of applications under section 203 of the FPA.

(a) The Commission will act on a completed application for approval of a transaction (*i.e.,* one that is consistent with the requirements of this part) not later than 180 days after the completed application is filed. If the Commission does not act within 180 days, such application shall be deemed granted unless the Commission finds, based on good cause, that further consideration is required to determine whether the proposed transaction meets the standards of section 203(a)(4) of the FPA and issues, by the 180th day, an order tolling the time for acting on the application for not more than 180 days, at the end of which additional period the Commission shall grant or deny the application.

(b) The Commission will provide for the expeditious consideration of completed applications for the approval of transactions that are not contested, do not involve mergers, and are consistent with Commission precedent.

d. Has the company investigated whether this process can be expedited?

RESPONSE:

See response to Interrogatory Number 12.a. above.

e. If so, what were the company's findings?

RESPONSE:
See response to Interrogatory Number 12.a. above.

13. On page 49, at lines 13-15, the witness states: "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 CO_2 case." Please explain why the described pattern was generally expected by DEF. Please identify and provide any documents or evidence DEF relied on to reach this conclusion.

RESPONSE:

The observation referenced from Mr. Borsch's testimony reflects on the results of the Detailed Economic Analysis presented in Exhibits BMHB-10 and BMHB-11. The resulting "Total" comparison values from those exhibits are combined in the table below for illustration purposes. The case named "Acquisition-PPA Mix 1" reflected more simple cycle resources. In contrast, the case named "PPA 1" reflected more combined cycle resources, as did the comparison of moving from inlet chiller uprates for three Hines units ("Self Build Case") versus four Hines units (the "Self Build Plus Hines 1 Chillers" case). To illustrate, in the *Reference Case*, the Self-Build case was preferred, but the CC-based "PPA 1 " case was $21M favorable to the "Acq-PPA Mix 1" case. In the *High Gas Case*, this difference increased to $28M favorable. The benefit of adding the Hines 1 CC uprate also improved from $26M to $41M favorable. This helps illustrate that High Gas case favors portfolios with more combined cycle resources. In the *No CO2 Case*, the difference between the "Acq-PPA Mix 1" and "PPA 1" cases decreased from $28M to $11M, which illustrates that the benefits of the combined cycles resources decline somewhat when the emission cost attributed to CO2 are removed.

Table of Consolidated "Total" Results from BMHB-10 and BMHB-11

	Acq – PPA Mix 1 (CT Based)	PPA 1 (CC Based)	Hines PB1-4 Chillers (CC Based)
Reference Case	($139M)	($118M)	$26M
Hi Gas Sensitivity	($138M)	($110M)	$41M
No CO2 Sensitivity	($170M)	($161M)	$14M

14. Exhibit No. BMHB-8 appears to indicate that Acquisition 1 and Acquisition-PPA Mix 2 were initially more cost-effective than PPA1. Please explain why Acquisition 1 and Acquisition-PPA Mix 2 were not considered in DEF's detailed economic analysis.

RESPONSE:

After the Initial Detailed Economic Analysis was completed, as represented by the results presented in Exhibits BMHB-8 and BMHB-9, Acquisition 1 was selected for further review. That alternative was included in DEF's FERC market screen analysis, as explained in pages 42 through 48 of Mr. Borsch's testimony. In the case of Acquisition 1, there was a finding in the FERC market screen analysis that an acquisition of this facility would likely not be approved without mitigation, which would render the Acquisition 1 alternative not cost effective. There was also a finding related to Acquisition 1 that additional gas fixed transportation would be required, above what was considered in the Initial Detailed Economic Analysis, which would also render the alternative not cost effective. At that point, the alternative was dropped from further consideration.

After the Initial Detailed Economic Analysis was completed, the planning team reviewed the range of remaining alternatives, including the acquisition and power purchase mixes that had been studied in the Initial phase. The planning team identified a different acquisition and power purchase mix, labeled as the new "Acquisition– PPA Mix 1" alternative in the final Detailed Economic Analysis, that was more specifically tailored to address the capacity need to provide more favorable economic performance than the "Acquisition – PPA Mix 1" and "Acquisition – PPA Mix 2" alternatives that had been considered in the previous phase of the analysis. In Exhibits BMHB-10 and BMHB-11, the results for the Self Build are shown to be favorable to the PPA and the Acquisition - PPA mix in the Reference case and both sensitivity studies. Please see documents previously produced in Bates range 14LGBRA-NRGPOD1-7-DOC 1.

15. For each cost category, identified in the first column of the table presented in Exhibit No. BMHB-8, please summarize the costs considered in each respective category.

RESPONSE:

Category	Description
Capital Cost	**Generation, Transmission, and Environmental Capital Projects**
Fuel	**Generation Fuel Costs, Start Up Fuel Costs**
Emissions	**CO2, SO2, NOx, Reagents Costs for DEF's fleet**
Variable Costs	**Variable O&M**
Fixed Costs	**Fixed O&M, Gas Reservation Charges**
PPAs	**Capacity Payments, Energy Payments, Fuel and Emissions Costs**
Cogens	**Capacity Payments, Energy Payments, Fuel and Emissions Costs**
Emergency Energy	**Emergency Energy Cost**

16. Please refer to Exhibit No. BMHB-10, for the following questions.

a. Do the bars associated with each data point represent the range associated with construction cost sensitivity and risks?

RESPONSE:

This response addresses the bars depicted in Exhibit BMHB-9. The bars associated with each data point represent the range associated with cost sensitivity risks associated with several factors including construction costs for the Suwannee and Hines projects, facility acquisition costs, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks. Please refer to the response to Interrogatory 10 for more detail discussion related to the sensitivity evaluation.

b. If yes, please provide the graph with data labels identifying the maximum and minimum value for each data point.

RESPONSE:

Please refer to the file bearing Bates Numbers 14LGBRA-STAFFROG1-16b-000001 attached entitled "140111_Staff_1st_ROG_10b.xlsx" for the chart requested.

17. Please complete the table below summarizing the revenue requirements for each Generation option listed in Exhibit No. BMHB-10. Please provide this information for the Reference Case, High Gas Price Case, and No CO2 Price Case. Please provide this information in electronic format (excel).

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
2032								
2033								
2034								
2035								
2036								
2037								
2038								
2039								
2040								
2041								
2042								
2043								
2044								
2045								
2046								
2047								

2048								
2049								
2050								
Total								

RESPONSE:

Please see chart attached in Bates range 14LGBRA-STAFFROG1-17-000001 through 14LGBRA-STAFFROG1-17-000013.

18. Referring to Exhibit No. BMHB-11:

a. Please explain in detail how the carbon cost forecasts were embedded in each line item of the "High Gas" and "No CO_2" tables for each portfolio evaluated.

RESPONSE:

The CO2 costs attributed to all resources accumulate in the results of each analysis in the row labeled "Emissions". Carbon costs also have a direct impact on the way that the generation fleet is dispatched because each fuel has a different CO2 emissions rate. The fuel that the units burn and their heat rates combined with the carbon costs, promote or penalize units in the dispatch order. Units that burn coal or distillate oil will have higher CO2 rates compared to units that burn natural gas (e.g. gas-fired units, cogens, PPAs) which will run more, as a result. The results of these impacts in the dispatch analysis will accumulate in the row labeled "Fuels".

As the relative dispatch changes as a result of CO2 and fuel costs, there will be other changes that directly correlate with dispatch that shift as well. Changes in reagent costs and emission costs other than CO2 will also accumulate in the row labeled "Emissions". Other smaller observable changes will accumulate in the "Variable O&M", "PPA", "Cogen" and "Emergency Energy" as well.

b. For each portfolio evaluated, please provide a detailed explanation on why and in which way the value of each of the line items was affected by assuming the carbon cost from (i) non-zero to (ii) zero.

RESPONSE:

The impacts of CO2 costs (either a forecasted value, or zero) on each line item in the analyses are explained above in section a. of this Interrogatory. Note that the results in the tables in BMHB-11 reflect differences in the CPVRR results for each case compared with the proposed Self-Build alternatives so these are relative comparisons of different resource portfolios responding to the various cost inputs. The impacts of CO2 costs on the

results of these analyses are also discussed in more detail in the response to Staff's 1st Interrogatory 13 in this docket.

For the purposes of the following interrogatory, please refer to the Direct Testimony of Benjamin M.H. Borsch, Exhibit No. BMHB-2, Duke Energy's 2014 Ten Year Site Plan (2014 TYSP).

19. For Schedule 2.1, Please provide the following information for both Columns (5) & (8) respectively. Please provide this information in electronic format (Excel).

    a. The Model Assumptions (rationale for variable selection and model specification).

    <u>**RESPONSE**</u>:

    The model assumptions and sources for column (5) are explicitly stated in Exhibit BMHB-2 page 28 of 76, General Assumptions #2 and #3. Service area population has consistently proven to be an excellent predictor of residential customer growth. By applying the Moody's projection of Florida household size, the projection captures the Great Recessions impact of population immobility and the recognized combination of households due to job loss and home foreclosure. For Column (8), the commercial class customer projection is driven by the amount of residential customers (3-month moving average), with the idea that commercial sector activity is driven to support the area population.

    Please see Load Forecast Work Papers – Documentation…for file names Hist_HHolds-Pop-HHSize.xlsx_201309 and Itron ND Models_Inputs & Output files CUST_RES & CUST_COM.

    Please see documents produced in response to NRG's First Request for Production, Number 6.

    b. The Regression Equation(s).

    <u>**RESPONSE**</u>:

    Please see Load Forecast Work Papers – Documentation…for file names Hist_HHolds-Pop-HHSize.xlsx_201309 and Itron ND Models_Inputs & Output files CUST_RES & CUST_COM. Each Itron model is a multiple tabbed file with all requested information.

    For input data sources see Exhibit BMHB-2 page 28 of 76, General Assumptions #2.

c. The Input Data Sets (if monthly – please specify ending month).

<u>RESPONSE</u>: All answers for Items c. through g. can be found in Load Forecast Work Papers – Documentation.

d. The Input Data Sources.

<u>RESPONSE</u>: Please see response to Interrogatory 19 a and c above.

e. The Predicted Data Sets.

<u>RESPONSE</u>: Please see response to Interrogatory 19 a and c above.

f. The Model Output (variable coefficients, all statistical analyses).

<u>RESPONSE</u>: Please see response to Interrogatory 19 a and c above.

g. The Forecast Data Sets (monthly – specify starting month).

<u>RESPONSE</u>: Please see response to Interrogatory 19 a and c above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

<u>RESPONSE</u>:
Yes. The commercial class customer forecast was shifted upward by 500 customers for the whole forecast horizon to better capture the recent trend in history

20. For Schedule 2.1, Please provide the following information for both Columns (6) & (9) respectively. Please provide this information in electronic format (excel):

a. The Model Assumptions (rationale for variable selection and model specification).

RESPONSE:
The model assumptions with sources for column (6) & (9) are explicitly stated in Exhibit BMHB-2 page 28-30 of 76. The rationale for variable selection always involves an economic variable deemed statistically correlated to the "class" energy sales.

b. The Regression Equation(s).

RESPONSE: **For responses to Items b. through g. please see Interrogatory 19 a and c above.**

c. The Input Data Sets (if monthly – please specify ending month).

RESPONSE:

Please see Interrogatory 19 a and c above.

d. The Input Data Sources.

RESPONSE:

Please see Interrogatory 19 a and c above.

e. The Predicted Data Sets.

RESPONSE: **Please see Interrogatory 19 a and c above.**

f. The Model Output (variable coefficients, all statistical analyses).

RESPONSE:

Please see Interrogatory 19 a and c above.

g. The Forecast Data Sets (monthly – specify starting month).

RESPONSE:

Please see Interrogatory 19 a and c above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

RESPONSE:
Out of model adjustments only include estimated impacts for plug-in electric vehicle and rooftop photovoltaic panel saturation.

21. Please refer to page 35 of 76, section "Peak Demand Forecast." Please provide the following for both in electronic format (excel) the "winter peak demand potential firm retail load forecast," and the "summer peak demand potential firm retail load forecast."

a. The Model Assumptions (rationale for variable selection and model specification).

RESPONSE:

The model assumptions for both the "winter peak demand potential firm retail load forecast," and the "summer peak demand potential firm retail load forecast" are based on the number of retail customers (excluding Street & Highway Lighting) drawing load on the DEF system at time of monthly peak. A determined effort to "add back" any historical direct load control (DLC) at time of monthly peak before commencing the modeling effort insures a consistent relationship between the independent variables and the dependent variable.

b. The Regression Equation(s).

RESPONSE:

All answers for Items b. through g. are identical to response Q19 c.

c. The Input Data Sets (if monthly – please specify ending month).

RESPONSE:

Please see Interrogatory 19 a and c above.

d. The Input Data Sources.

RESPONSE:

Please see Interrogatory 19 a and c above.

e. The Predicted Data Sets.

RESPONSE:

Please see Interrogatory 19 a and c above.

f. The Model Output (variable coefficients, all statistical analyses).

RESPONSE:

Please see Interrogatory 19 a and c above.

g. The Forecast Data Sets (monthly – specify starting month).

RESPONSE:

Please see Interrogatory 19 a and c above.

h. Any Out of Model Adjustments and associated rationale for each such adjustment and source of adjustment. If the adjustment is calculated, please show the calculations.

RESPONSE:

Out of Model Adjustments are commonly made to projections of retail potential monthly peak demand, all with the intent to best capture the historical trend with known anomalies where either solid estimates exist, or does not exist. Retail monthly peak demand is expected to occur on a weekday. Winter month peaks are expected to occur in the morning at "normal" weather conditions. Summer month peaks always occur in late afternoon. Peaks during activated load control often are pushed off an hour or two when typical usage patterns are different than hour of expected peak. Weekend or holiday peaks often occur in the winter when normal winter peaking weather conditions do not occur on a week day. This will result in a lower peak load due to industry being at reduced levels or school load being off. Lastly, summer rain influence on peak demand is very difficult to measure. Capturing rain impact from weather station rainfall levels is "hit or miss" with the typical "localized" thunder storm patterns in Florida afternoons.

22. When was the load forecast discussed in witness Borsch's Direct Testimony prepared and was it reviewed by executive management? If so, what was the review process?

RESPONSE:

The load forecast in question was prepared in late fall 2013. DEF's load forecast is not reviewed by "executive management" given that the term "executive management" would mean Duke Energy's Senior Management Committee which consists of Duke Energy's most senior executives. However, DEF's load forecast is reviewed and approved by the Vice President of Corporate Strategy following section Director approval prior to it being used for planning purposes.

23. Please refer to Schedule 2.3, Column (2), titled "Sales for resale GWh." Please explain the significant drop in sales from 2013 (1,488) to 2014 (936).

RESPONSE:

This drop in "Sales for Resale GWh" is two-fold. First, weather conditions in 2013 were slightly milder than normal, but rainfall was extremely high reducing the need for energy under the DEF "peaking strata" contracts during the summer months. Second, DEF wholesale contracts for competitive spot market offers available to wholesale entities were not as competitive under market conditions resulting in a lower load factor in the projection of wholesale energy.

24. Please refer to Schedule 3.1, Column (4), titled "Retail." Please explain the significant increase in the retail summer peak demand from 2013 (9,000) to 2014 (9,555).

<u>**RESPONSE**</u>:

The retail summer peak of 8/12/2013 at hour ending 5pm occurred at a 5-Hr system weighted temperature of over two degrees Fahrenheit cooler than normal expected conditions. More than 0.5 inches of rainfall was recorded on this peak day at the Orlando weather station, DEF's largest load center.

Also, an expected 22,200 more retail customers are expected to be drawing load during the summer peak 2014.

25. Please refer to Schedule 3.2, Column (4), titled "Retail." Please explain the significant increase in the retail winter peak demand from 2013 (8,274) to 2014 (10,231).

RESPONSE:

The retail winter peak of 2/18/2013 at hour ending 8am occurred at a 2-Hr/24-Hr system weighted temperature of nearly four degrees Fahrenheit warmer than normal expected conditions. Also, this winter peak occurred on a Monday morning which typically has lower peaks than other weekday peaks - all else being equal. Weekend load patterns have not completely shifted to a typical weekday load pattern

Besides the reasons mentioned above not expected to occur in the winter of 2013/14, the number of retail customers expected to be on the DEF system at time of peak will be higher by 22,200.

The following questions refer to the direct testimony and exhibits of Mark E. Landseidel.

26. On page 5, the witness states that The Suwannee Simple Cycle project is a state-of-the-art combustion turbine generation project. Please describe DEF's experience with F class combustion turbines.

<u>**RESPONSE**</u>:

DEF has 13 F class combustion turbines in operation including the vendor and model chosen for the Suwannee Simple Cycle Project.

Site	**Unit**	**MFG**	**Model**	**Type**	**COD**	[redacted]
Bartow CC	BRR-4A	Siemens	501FD3	F-Class	2009	Reggie Anderson
Bartow CC	BRR-4B	Siemens	501FD3	F-Class	2009	Reggie Anderson
Bartow CC	BRR-4C	Siemens	501FD3	F-Class	2009	Reggie Anderson
Bartow CC	BRR-4D	Siemens	501FD3	F-Class	2009	Reggie Anderson
Hines	HGP-1A	Westinghouse	501FC+	F-Class	1998	Tony Salvarezza
Hines	HGP-1B	Westinghouse	501FC+	F-Class	1998	Tony Salvarezza
Hines	HEC-2A	Westinghouse	501FD2	F-Class	2003	Tony Salvarezza
Hines	HEC-2B	Westinghouse	501FD2	F-Class	2003	Tony Salvarezza
Hines	HEC-3A	Westinghouse	501FD2	F-Class	2005	Tony Salvarezza
Hines	HEC-3B	Westinghouse	501FD2	F-Class	2005	Tony Salvarezza
Hines	HEC-4A	GE	7FA.03	F-Class	2007	Tony Salvarezza
Hines	HEC-4B	GE	7FA.03	F-Class	2007	Tony Salvarezza
Tiger Bay	TBG	GE	7FA	F-Class	1995	Tony Salvarezza

27. On page 6, the witness states that the "only land that must be purchased [for the Suwanee Combustion Turbine project] is an additional 24 acres." How many acres is the Suwanee site absent the additional 24 acres?

<u>**RESPONSE**</u>:

Total site excluding the new purchase is 635 acres.

28. Is there existing and sufficient natural gas supply at DEF's Suwannee power plant site that can support the proposed Suwannee Simple Cycle project?

__RESPONSE__:

Yes. There is sufficient natural gas supply to support the proposed Suwannee Simple Cycle Project.

29. On page 7, the witness indicates that DEF plans to employ lessons learned and best practices from prior Duke Energy successful gas turbine projects on the Suwannee Simple Cycle project. Please provide an example of lessons learned and best practices the DEF plans to employ.

RESPONSE:

DEF added safety supplemental requirements to the engineering, procurement and construction contract requirements that were developed based on lessons learned from these prior projects.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of cost effective generation alternative to meet need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI DATED: August 14, 2014

DUKE ENERGY FLORIDA, INC.'S *REVISED* RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NO. 30)

Duke Energy Florida, Inc. ("DEF") hereby provides its revised response to Staff of the Florida Public Service Commission ("Staff") First Set of Interrogatories to Duke Energy Florida, Inc. specifically as to Interrogatory Number 30 to correct typographical errors that were inadvertently included in the original response.

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's First Set of Interrogatories (Nos. 1-55), served on July 7, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

30. On page 7 the witness states that DEF has "successfully executed several simple combined cycle gas turbine projects." Please complete the table below summarizing the actual and originally projected costs of past DEF combined cycle projects.

	Originally Project Cost ($Millions)	Actual Cost ($Millions)
Buck		
W.S. Lee		
Hines		
Bartow		
H.F. Lee		
Dan River		
Sutton		

REVISED RESPONSE:

Revisions are indicated in blue below.

	Originally Project Cost ($Millions including AFUDC)	Actual Cost ($Millions including AFUDC)
Buck CC - 2011	$660	$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	$709	$662
Sutton CC - 2013	$731	$560

31. Please complete the table below for Buck, H.F. Lee, Bartow Combined Cycle, W.S. Lee, Hines 3 and 4, Dan River, and Sutton.

Net Generation MW (Summer)	
Installed Cost ($ Million)	
Fixed O&M ($/kw-yr)	
Variable O&M ($/MWh)	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	
In-Service Date	
Location	

RESPONSE:

The performance data provided in this response were 2013 actuals obtained from DEF's MicroGADS reporting system. The operating cost data provided in this response were 2013 actuals obtained from DEF's GKS industry data reports. Actual reported performance and cost data are expected to vary from year to year reflecting normal operations and maintenance cycles for the units. Please refer to the attached confidential file entitled 14011_Staff_1st_Rog_31.xlsx, bearing Bates Number 14LGBRA-STAFFROG1-31-000001 for the requested data. This file is confidential and subject to DEF's Tenth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

32. On page 8, the witness discusses cost estimates associated with the proposed Suwanee Simple Cycle Project. Please describe how DEF developed its capital and O&M cost estimates for the proposed Suwanee Simple Cycle Project.

<u>**RESPONSE**</u>:

The project team developed the Suwannee Simple Cycle Project scope and site requirements and built the project capital cost estimate based upon Duke experience and Owner's Engineer support. The Combustion Turbine Supply Contract (firm bid), Generator Step-Up Transformers Supply Contract(firm bids), and Engineering, Procurement and Construction (EPC) Contract (firm bids) make up approximately 70% of the project capital cost and for these firm price bids were obtained that further support the estimate.

Duke Energy Power Generation Operations provided the O&M cost estimates for the Suwannee Simple Cycle Project based upon their experience with 13 DEF F class turbine operations and maintenance.

33. On page 9, the witness states that "Suwannee Simple Cycle is expected to operate at a capacity factor range consistent with its peaking generation capacity role on DEF's system. What is the projected average annual capacity factor for the proposed Suwanee Simple Cycle Project?

RESPONSE:

The projected average annual capacity factor for the proposed Suwanee Simple Cycle Project is 9.3% (TYSP).

34. On page 12, the witness states that "the Hines Chillers Power Uprate project further achieves this significant increase in the Company's summer capacity with a minimal increase in the fixed and variable O&M costs at HEC." Please complete the table below comparing the Hines 1-4 with and without the proposed chillers.

Net Generation MW (Summer)	
Fixed O&M ($/kw-yr)	
Variable O&M ($/MWh)	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	

<u>**RESPONSE**</u>:

A table summarizing this response is provide in file attached entitled "140111_Staff_1st_ROG_34.xlsx" bearing Bates number 14LGBRA-STAFFROG1-34-000001.

35. On page 12, the witness states that "Air inlet chilling is common in the industry, and there have been a number of air inlet chilling uprates to F class combustion turbines similar to the F class turbines in the Hines Power Block units."

a. How many existing DEF power plants could have chiller systems installed?

RESPONSE:

None of DEF's plants currently employ air inlet chillers. However, systems similar to the system proposed at Hines have been installed at Duke Energy's Buck and Dan River facilities in North Carolina.

b. Is DEF planning to install chillers to any existing plants other than the proposed chillers?

RESPONSE:

DEF considered the potential for installation of inlet chillers at the Bartow combined cycle facility, but there were some transmission limitations identified that have not yet been addressed or resolved, so these units may or may not be considered for upgrades at some point in the future. Also, the Company initially considered the option for inlet chillers at the proposed new Citrus combined cycle facility, but is not installing these systems initially. These new generating units will meet the Company's energy and capacity needs without the inlet chillers, given the new technology options and high efficiency provisions that are being employed. The Citrus project team is, however, including the potential for future addition of inlet chillers in the design of the new facility to help ensure that it will be feasible to add these systems in the future when the needs arise.

c. If no, please explain why not.

RESPONSE:

Not applicable.

36. Please complete the table below summarizing the actual and projected water usage at DEF's Hines Energy Complex.

	million gallons per day
2004	
2005	
2006	
2007	
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

<u>RESPONSE</u>:

The Hines Energy Complex uses predominately alternative water supplies (AWS) for cooling needs and for other uses. These supplies include, but are not limited to: use of 100 percent of the reclaimed water from the City of Bartow waste water treatment plant; on-site stormwater capture and storage (known as "water cropping"); recycled industrial wastewater from the Hines and nearby Duke Energy Tiger Bay Cogeneration facilities; and recycled industrial wastewater from the nearby Mosaic Co. Green Bay and Hookers Prairie facilities. No traditional surface freshwater supplies (such as pumping from a river or stream) are used at the facility.

Groundwater (excluding small amounts used for domestic purposes and as makeup supply to produce demineralized water) is allowed as a backup cooling water supply source, but only under a restrictive set of operating conditions and only after the alternative supplies are fully utilized. With four power blocks, Hines is authorized

to use groundwater up to 5.015 mgd annual average daily flow (8.8 mgd peak monthly average daily flow maximum) per Conditions of Certification PA 92-33I, Section B, II.A.30. A table of (groundwater) use is provided in the file attached entitled "140111_Staff_1st_ROG_36.xlsx" bearing Bates Number 14LGBRA-STAFFROG1-36-000001.

While the chiller project will result in increased evaporative loss due to operation of the chiller cooling towers, it is expected that this will also be offset by condensate generated by the chillers and will be adequately made up with existing AWS sources as well as future AWS projects. Regardless, use of groundwater is not expected to increase beyond recent historical usage as a result of chiller operation, nor are additional groundwater supplies being requested.

37. Please list all sources relied on for the cost estimates listed in MEL-7.

RESPONSE:

MEL- 7 Estimate Category	$ Million
Major Equipment and Engineering, procurement and Construction (EpC)	$120
Owners Costs including Contingency	$30
Subtotal Project Estimate	**$150**
AFUDC	$10
Total Project Cost	**$160**

Kiewit Power Engineers (KPE) was the engineer of record for two of the Hines power blocks and KPE has been engaged as the Owner's Engineer for the Hines Chiller Uprate Project. KPE assisted in putting together the preliminary estimate for the Hines Chiller Uprate Project. In addition an inlet chiller package supplier with experience in both new and retrofit inlet chilling projects provided indicative pricing that further supported the capital cost estimate. This advice, together with Duke project and estimating experience, provided the basis for the cost estimate.

38. Please discuss how the cost estimates summarized in MEL-7 compare to the actual project costs of other Chiller projects.

RESPONSE:

Inlet Chilling was installed on the Duke Energy Carolinas Dan River CC Project at the time the plant was built and the cost was $25-30 million (order of magnitude) for the one 2X1F block (2012 commercial operation). For simplicity if the $25-30 million is multiplied by 4 (e.g. four 2X1F blocks at Hines) the projected cost would be in the range of $100 to $120 million.

The following questions refer to the direct testimony and exhibits of Julie Solomon.

39. Exhibits JS-9 through JS-12 indicate that the Herfindahl-Hirschman Index (HHI) would only change by a large enough amount to trigger market concerns with FERC under certain conditions and at certain times, but that the HHI would lower or stay the same at other times.

    a. Does the failure of the Competitive Analysis Screen at any time constitute a screen failure, or are further conditions also required to be met?

__**RESPONSE**__:

Screen failures refer to any scenario or time period in which the HHI changes exceed the threshold allowed given market concentration. See, also, Solomon testimony, page 9, lines 6-10.

    b. Does a failure of some screens, rather than all screens, change in any way the potential appeals or mitigation measures available to the company?

__**RESPONSE**__:

Whether there are potential appeals is a legal question, and Ms. Solomon is not a lawyer. Mitigation, if required, is intended to remedy any such screen failures.

40. On page 9 the witness quotes FERC that, "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."

a. What is meant on page 9, lines 13-15, by "no facts such as these have been relied on by FERC in previous orders or have been identified in the acquisitions at issue"?

<u>RESPONSE</u>:

The referenced sentence, corrected, should read as follows: "no facts such as have been relied on by FERC in previous orders have been identified in the acquisitions at issue" –

The point being made is that Ms. Solomon has not identified the market conditions FERC cites ("demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved") as a basis for indicating a lack of competitive concern in the instant situation.

b. Did the company investigate providing evidence that there was a lack of a competitive problem if they made the potential acquisitions? How was this decision reached?

<u>RESPONSE</u>:

Please see DEF's response to Interrogatory Number 40.a. above.

c. Has the company ever provided evidence of a lack of a competitive problem before FERC? If so, please provide examples.

<u>RESPONSE</u>:

Ms. Solomon is aware that the economic witness on behalf of Duke in connection with the Duke Energy-Progress Energy merger argued that certain screen failures did not necessarily indicate evidence of competitive concerns. See Testimony of William H. Hieronymus in Docket No. EC11-60.

41. For purposes of the following request, please refer to, page 7, lines 10-12.

a. Please identify which "ratings" from EIA Form 860 were used in the analysis.

RESPONSE:

The most recent EIA Form 860 data available are for 2012.

b. Were the ratings data used in the analyses specific to the Acquisition 1 facility and the Acquisition 2 facility?

RESPONSE:

The ratings for the Acquisition 1 and Acquisition 2 facilities also were based on the EIA Form 860 for the same year.

c. If the response to (b) is negative, please explain what data were used and why facility-specific data were not used.

RESPONSE:

Not applicable.

42. For purposes of the following request, please refer to DEF witness Solomon's Exhibit (JS-4). Please identify the source for this exhibit.

__RESPONSE__:

Exhibit JS-4 is a tabular representation of FERC's guidelines, described on pages 11 and 12.

43. For purposes of the following request, please refer to page 12, lines 12-13. Are the vertically integrated utilities to which reference is made typically monopoly providers within a given geographic area?

RESPONSE:

Utilities with load-serving obligations, including vertically-integrated utilities, typically have an exclusive franchise service area. The scope of the geographic area (e.g., a BAA), however, is sometimes broader than a single utility's service area and includes more than a single generation owner. Markets can be highly concentrated for a number of reasons.

44. For purposes of the following request, please refer to page 13, lines 23 through page 14, line 1. Please explain to what "related marginal costs" refers and how they are factored into the analysis.

<u>RESPONSE</u>:

The reference to marginal costs refers to the underlying costs of the generation technology presumed to be setting the market price at the time of the sale. Historical EQR prices are adjusted to reflect a forward-looking price using the change in historical gas prices and an analysis of the generating technology during each of the ten time periods. For example, if the future gas price was forecast to be $1/mmBtu higher than the historical gas price and the generating technology assumed to be setting the price is a gas-fired combined-cycle plant with a heat rate of 7,000 btu/kWh, the historical EQR price would be adjusted upward by $7/MWh ($1/mmBtu * 7,000 btu/Kwh).

45. For purposes of the following request, please refer to page 15, lines 11-12. Please explain how Simultaneous Import Limit (SIL) is measured or computed. (E.g., is it primarily a function of unreserved transmission capacity available at a given time in a particular geographic market?)

<u>**RESPONSE**</u>:

SIL values are intended to quantity "a study area's simultaneous import capability from its aggregated first-tier area". See *Puget Sound Energy, Inc.* 135 FERC ¶ 61,254 (2011), Bates number 14LGBRA-STAFFROG1-45-000001 through 14LGBRA-STAFFROG1-45-000028. Details of how to calculate SILs in the context of FERC's analysis are contained in the referenced order, a copy of which is attached. Unreserved transmission capability is relevant, but it is not the sole determinant, because unreserved transmission capability from multiple sources potentially is not available simultaneously.

46. For purposes of the following request, please refer to page 16, lines 19-23. Please identify as of what date the values for the generation portfolio were determined.

<u>**RESPONSE**</u>:

The analysis is based on a forward-looking, 2015 snapshot.

47. For purposes of the following request, please refer to page 17, lines 5-7.

a. Please identify the peak load forecast used and the time period covered by the forecast.

<u>RESPONSE</u>:

DEF's peak load forecast for 2015 was used. The forecast is from *Progress Energy Florida, Inc., Ten-Year Site Plan*, April 2013.

b. Please describe how historical hourly load data was used to build an "hourly-load shape."

<u>RESPONSE</u>:

The ten time periods analyzed are identified in Exhibit JS-5. Historical loads (for the twelve-month period ending November 2012) were sorted into each of the ten time periods. (At the time of the analysis, the latest hourly data for the DEF BAA was for 2012.) For example, the top 10% of hourly loads occurring in the peak summer hours comprised the load for the Summer Super Peak 2 (S_SP2) period, and all off-peak hours in the summer comprised the load for the Summer Off-peak (S_OP) period. Thus, the hourly load shape for the twelve-month period ending November 2012, combined with the peak load and energy forecast for 2015 was used to populate each of the ten time periods.

48. For purposes of the following request, please refer to page 17, lines 15-18.

a. Please indicate the specific Electric Quarterly Reports (EQR) that were used in the analysis (i.e., as of what date are the prices and whether they reflect DEF and non-DEF price data).

<u>RESPONSE</u>:

Please see DEF's response to NRG's 2nd set of interrogatories, 113.

b. By way of clarification, is the forward-looking period calendar year 2015?

<u>RESPONSE</u>:

Yes.

c. Please describe how the forward-looking prices were derived.

<u>RESPONSE</u>:

Please see response to NRG's 2nd set of interrogatories, 114.

49. For purposes of the following request, please refer to page 17, lines 19-23 through page 18, lines 1-7.

a. Referring to page 17, line 23 through page 18, line 1, please clarify what is meant by the assumption that the "output was fully importable." (E.g., that there is sufficient transmission in place?)

RESPONSE:

When analyzing Acquisition 2, all of the facility's capacity was assumed to be deliverable to the DEF BAA, irrespective of the underlying SIL assumption.

b. Please describe how the number of potential suppliers allocated shares of the SIL were estimated.

RESPONSE:

For the analyses presented in Exhibits JS-9 through JS-12, the analysis assumed that there were four competing suppliers: a single 5,000 MW potential supplier and three 1,000 MW potential suppliers. These suppliers were each allocated a share of imports based on their relative shares (i.e., the 5,000 MW supplier would be allocated 62.5% of the SIL (5,000/8,000) and each of the other suppliers would be allocated 12.5% of the SIL. The single 5,000 MW potential supplier was included to reflect that Southern Company – located in a market interconnected to DEF – has a relatively large amount of AEC. This was intended to be a simplifying assumption. See page 18, lines 4-6.

c. Please indicate how the number of potential suppliers were either estimated or otherwise determined.

RESPONSE:

Please see DEF's response to Interrogatory Number 48.b. above.

d. Referring to page 18, lines 6-7, please explain why the aforementioned assumptions "had no material effect on the results of my evaluation."

<u>**RESPONSE**</u>:

In the analysis, imports (the SIL) represent a relatively small portion of the overall market size. Hence, market concentration is driven largely by the amount of internal supply (i.e., DEF's market share has a significant effect on overall market concentration.)

50. For purposes of the following request, please refer to DEF witness Solomon's Exhibit (JS-6). To the extent not provided in response to Interrogatory No. 12(c), please describe how the prices on this exhibit were derived.

RESPONSE:

Please see DEF's response to NRG's 2nd set of interrogatories, 114.

51. For purposes of the following request, please refer to page 18, lines 20-23 through page 19, line 1. Please explain how "one can demonstrate that the results of the Competitive Analysis Screen do not turn on the specific SIL level."

RESPONSE:

One can test the results by inputting alternative SILs.

52. For purposes of the following request, please refer to DEF witness Solomon's Exhibit (JS-8). This exhibit indicates that with a 10% price increase, additional AEC becomes available in five additional time periods. Please explain mathematically how economic capacity, and thus AEC, increases but total generation and LT purchases, and load, do not change. Please clarify any assumptions that underlie these calculations.

RESPONSE:

FERC's convention is to change price levels for sensitivity analysis but to make no other changes (i.e., no changes to underlying costs, load, etc.) The DPT, in effect, takes as an input the operating costs of units, and a specified "destination market price", and determines whether the units are economic within 105% of that destination market prices. If you raise the market price in a sensitivity analysis, generating units that previously were not economic may become economic. Specifically, at higher prices, additional DEF generating units become economic under the Competitive Analysis Screen. Exhibit JS-8 is based on Exhibits JS-6 and JS-7. As shown in Exhibit JS-8, for example, in the S_SP2 time period, the total amount of DEF generation that is economic at a market price of $63/MWh is 8,210 MW. At a market price of $69/MWh, DEF's economic generation increases to 9,005 MW.

53. Please refer to page 10 of witness Kevin Delehanty's direct testimony for the following questions:

a. Referring to lines 14 – 19, please provide DEF's carbon cost forecasts used in the instant need determination case in dollars per ton ($/ton) for the forecast period, 2014 through 2040, expressed in 2014 dollars.

RESPONSE:

See DEF's Response to Calpine's First Set of Interrogatories Number 4.

b. Please identify all the assumptions DEF used in developing its carbon cost forecasts.

RESPONSE:

The following is the set of specific assumptions that helped guide the development of our CO_2 price forecast. In addition, please refer to DEF's response to question 14c for a discussion of the analysis that lead to our current CO_2 price forecast.

- **EPA is in the early stages of developing a CO_2 regulation for existing fossil-fueled electric generating units. It is not known whether the regulation will establish a price on CO_2 emissions.**
- **While the economy has improved, the main focus of Congress and the White House for the next few years will be on taking actions to create jobs, lower the national debt, and restructure entitlement programs. There will be no successful legislative efforts to enact any federal greenhouse gas regulatory program during this period.**
- **Florida will not move on its own to establish greenhouse gas regulatory programs that establish a price on CO_2 emissions.**
- **Despite the lack of focus on climate change among federal policymakers, the issue will continue to be a major focus of environmental groups who will continue to campaign for federal legislation.**

- **The economy will continue to improve during the period 2013 to 2016 such that after the 2016 Presidential election, there could be more of a willingness among policymakers to consider some sort of climate change legislation.**
- **Potentially, with the support of the utility sector, some form of federal climate change legislation will be enacted in 2017 that would take effect in 2020.**

c. Please provide a detailed description of the methodology used to arrive at estimated future carbon costs discussed in question (a).

RESPONSE:

At the time Duke Energy Florida 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, with the Republicans still in control of the House, and the Democratic majority in the Senate less than the 60 votes needed to invoke cloture, Duke Energy Florida sees no indication that climate change legislation designed to establish a price on CO_2 emissions will be seriously debated through at least 2014.

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, Duke Energy Florida considers it unlikely that a carbon tax will be adopted in the near term because we do not believe the Republican-controlled House would support such a measure. Therefore, Duke Energy Florida does not believe that Congress will consider legislation in the near term that establishes a price on CO_2 emissions.

While Duke Energy Florida 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. This is why Duke Energy Florida believes it is reasonable to considered such an outcome.

Duke Energy Florida'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. Duke Energy Florida is not predicting what form any such legislation may take.

The outcome of the legislative debate that occurred in 2009 and early 2010 is informative to the prices we are using today. As evidenced by the 2009 debate over the Waxman-Markey legislation, there are many strongly held differences of opinion within the Democratic and Republican caucuses and between members of Congress representing different regions of the country regarding climate change legislation. It is not simply a Democrat versus Republican issue. For example, members of both parties from states with farm- and industrial-based economies expressed concerns about the impact of climate change legislation on manufacturing and energy prices; coal state members expressed concerns that climate change legislation would hurt the mining economy; and members from states that have historically relied on coal-fired generation expressed significant concerns over increased electric costs to consumers.

Duke Energy Florida believes a primary reason for the failure of climate change legislation in 2009 was concern that the legislation would lead to higher energy prices that would have had an adverse impact on the economy. It is reasonable to assume that this same concern will be present during any future debate over federal climate change legislation. In addition, regional differences, more than those between the political parties, could have a great bearing on the outcome of any future debate in Congress over climate change legislation that might occur. Reaching consensus on this issue will require compromise. At the end of the day, however, Duke Energy Florida believes that if Congress does enact legislation that sets a price on CO_2 emissions, it will do so cautiously to minimize the impacts to the economy. Therefore, Duke Energy Florida believes that if Congress does enact climate change legislation establishing a price on CO_2 emissions, it will not enact a program that will produce initially high prices so as to avoid shocking the economy. The reference case CO_2 price forecast being used by Duke Energy Florida is consistent with the lower end of the range of prices that were predicted by the EPA for the Waxman-Markey legislation. Additionally, after the failure of the Waxman-Markey legislation, subsequent debate focused on the concept of a price collar that would set minimum and maximum prices for CO_2. This concept is a cost control mechanism that demonstrates the concerns many had about enacting any program without cost containment so the policy would not adversely impact the economy.

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, Duke Energy Florida also considers an alternative scenario where the price on CO_2 emissions is zero.

The EPA's recently proposed Clean Power Plan was not a consideration in the development of Duke Energy Florida's CO_2 price forecast. Please refer to our response to question 53h for a discussion of the EPA's proposed Clean Power Act and its potential influence on Duke Energy Florida's CO_2 price forecast.

d. Please identify whether the carbon cost forecasts used in the instant case were derived in-house or by outside consultant(s). If the response is the latter, please identify each of these consultants and provide a copy of their reports, findings or other analyses.

<u>RESPONSE</u>:

Duke Energy Florida's carbon cost forecast was developed in-house.

e. Please explain whether DEF used the analysis of past potential legislation for creating a market price for carbon as the basis for developing its forecasted carbon costs discussed in question (a). If so, please provide a summary of that analysis.

<u>RESPONSE</u>:

Duke Energy Florida did not directly use analyses of past potential legislation when it created its current carbon price forecast. We did, however, consider analyses of the 2009 Waxman-Markey legislation (H.R. 2454) as data points in the development of our forecast. Specifically, once we identified a potential price forecast, we compared it to the range of prices predicted by the EPA and the Energy Information Administration for the Waxman-Markey legislation to judge the reasonableness of our price forecast.

f. If the response to question (e) is affirmative, please explain why DEF believes this approach to estimating the future cost of carbon is appropriate given the past legislation for creating a market price for carbon was not enacted.

<u>RESPONSE</u>:

As explained in our response to question 53e, while we did not use analyses of the Waxman-Markey legislation as a direct input into our decision making about our carbon forecast, we did use analyses of the Waxman-Markey legislation as a point of reference to assist us in judging the reasonableness of our forecast. While we recognize that the legislation was not enacted, it was in fact the first legislation of its kind to pass at least one house of Congress, meaning it had the support of many in Congress. In the absence of any formal or informal legislative or regulatory proposals at the time our current forecast was developed, we considered the Waxman-Markey legislation to be a reasonable representation of the stringency of climate legislation that Congress might consider passing in the future.

g. If the response to question (e) is negative, please describe other approaches or methodologies, if any, DEF considered in developing its carbon cost forecasts.

<u>RESPONSE</u>:

Duke Energy Florida's carbon price forecast primarily reflects our best judgment as to what a reasonable price trajectory might be given the fact that there was no legislative or regulatory proposals in play at the time our forecast was developed. Please also see our response to question 53f and 53j for additional discussion.

h. Will DEF plan to update or modify its carbon cost forecasts by taking into consideration EPA's recently published draft carbon emission guidelines for existing stationary sources for electric utility generating units (Clean Power Plan), which proposed a statewide CO2 target for Florida? Please explain your answer and DEF's expected implementation schedule for the proposed Clean Power Plan.

RESPONSE:

Duke Energy Florida is currently evaluating whether it should update its carbon forecast in response to the EPA's recently proposed Clean Power Plan, and if so, how it should update the forecast. No decision has been made at this time. The issuance of EPA's Clean Power Plan proposal does not eliminate the uncertainty surrounding future carbon policy. For example, assuming the EPA finalizes the Clean Power Plan essentially as it has been proposed, there are multiple potential forms that state regulations implementing the requirements of the emission guidelines could take, and each would likely have a different associated cost. For example, regulations could take the form of a command-and-control type program, or they could take the form of some sort of emissions or emission rate averaging or trading program. The state of Florida could choose to implement its program only within the state's borders, or it could choose to join with other states in implementing the requirements of the EPA emission guidelines. The fact that there are still multiple potential pathways for implementation of carbon regulation in Florida in response to EPA's proposal makes determining the appropriate carbon cost forecast challenging. More will be known when EPA finalizes its proposal in June of 2015, but until the state develops its implementation plan, there will still be uncertainty. There is also the uncertainty that results from expected legal challenges to EPA's final emission guidelines and whether the courts will require changes to whatever EPA finalizes. Finally, there is the possibility that EPA's final emission guidelines could be substantially different from what has been proposed, which creates additional uncertainty.

Duke Energy Florida's implementation schedule will be such that it supports meeting whatever regulatory requirements are placed on it by the state, but we do not have a specific schedule at this time because we are years away from knowing what those requirements will be. Based on the EPA's proposal, it is likely that some measures could be required to be implemented as early as 2020. The EPA has proposed that the interim compliance period extend from 2020 to 2029, with the final compliance period starting in 2030. The EPA asks for comment on an alternative approach that would have the interim compliance period extending from 2020 to 2024, with the final compliance period starting in 2025. Under section 111(d) of the Clean Air Act, the states have the responsibility for developing the source-specific regulations for implementing the emission guidelines that EPA establishes. The EPA's emission guidelines will therefore not impose regulatory requirements on any of Duke Energy Florida's affected power plants. Based on EPA's proposal, the state of Florida can take from June 2016 to June 2018 to finalize its regulatory plan and submit it to EPA for approval. EPA expects to take up to a year to review and approve or disapprove a state plan.

i. Please elaborate, in detail, on the statement "[t]he carbon price Duke Energy currently uses in its fundamentals forecast is a direct input to the process." What is meant by the term "the process" appearing in this statement? (lines 14-15).

RESPONSE:

The "process", is the process of developing the Company's fundamental fuels forecast. The development of the Company's fundamental fuels forecast is explained in detail in the testimony of Kevin Delehanty.

j. Referring to lines 16-17, please explain why DEF believes the carbon price DEF currently used was "a reasonable trajectory to represent the risk of federal climate legislation or regulation given the current uncertainty surrounding such policy."

RESPONSE:

Please refer to our response to question 53c for a discussion of the analysis that lead to our current CO_2 price forecast and why we believe the forecast is reasonable. Given the fact that at the time we developed our price forecast there were no active legislative or regulatory proposals that could be used to guide our thinking on the matter, the development of our price forecast by necessity had to rely heavily on our best judgment of what might occur in the future.

54. Please complete the table below summarizing the results of DEF's fuel cost forecast. Please provide this information for the fuel forecast used in this docket, the Company's most recent rate case, the Company's Ten Year Site Plan filed in 2014, and in Docket No. 130200-EI.

	Delivered Fuel Price Forecast (Nominal)		
	Natural Gas ($/MMBtu)	Oil ($/MMBtu)	Coal ($/MMBtu)
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
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2050			

RESPONSE:

Please see the table attached to this response bearing bates number 14LGBRA-STAFFROG1-54-000001.

The table shows price forecasts for the current docket and for the 2009 DSM goal setting docket. The forecast for the current docket is the same as that used in the 2014 Ten-Year Site Plan and as that used in Docket 130200-EI. The forecast used in the last (2009) rate case presented only a single year (2010) forecast.

55. Witness Delehanty discusses DEF's fundamental fuel forecast.

a. Please describe the inputs and assumptions used in developing the fuel cost forecast(s).

RESPONSE:

The fuel cost forecasts are constructed for each generation facility by combining three to five years of visible futures market prices with a long term fundamental price forecast beyond year five and then adding in plant specific transportation costs and fees. Fuel prices beyond 2033 were calculated by smoothing the final five years of fundamental prices and then escalating those prices beyond the final forecast year (2037) at a long term escalation rate of approximately 3% /yr. The market prices for the initial five years originate from liquid trading hubs like the New York Mercantile Exchange (NYMEX) as well as broker quotes, contracts and responses to fuel supply RFP's.

The primary inputs and assumptions used in DEF's fundamental forecast are contained within the 2013 EVA Long Term "Fuelcast" Outlook, published in the Fall of 2013 as well as a list of assumptions requested by Duke Energy. Duke Energy subject matter experts reviewed EVA's 2013 outlook as well as their input assumptions and requested specific changes to better align the forecast with Duke Energy's own internal planning assumptions. It is important to note that Duke Energy adopted all of EVA's upstream supply and demand data assumptions for the oil, gas and coal sectors, which means that Duke Energy did not adjust the fuel supply curves, or any of the demand curves outside of the power sector. Duke Energy limited its assumption changes to areas within the power sector, and areas of environmental and regulatory policy where Duke Energy feels it has attained a level of subject matter expertise. Please see the excel workbooks: attachment (###) <2013_09_06 - FuelCast 2013 LT - Modeling Assumptions.xlsm> for a list of EVA's input assumptions and attachment (###) <2013 Fall Refresh Duke Assumption Changes.xlsx > for the specific changes requested by Duke Energy. These confidential documents bear Bates numbers 14LGBRA-STAFFROG1-55-000001 through 14LGBRA-STAFFROG1-55-000005 and are subject to DEF's Tenth Notice of Intent to request confidential classification filed contemporaneously with the service of this response.

b. Please identify all third party consultants relied upon in developing the fuel cost forecast(s).

<u>**RESPONSE**</u>:

Duke Energy only relied upon EVA's Fall 2013 Long Term Outlook (Fuelcast) in the development of the Duke Energy Fall 2013 Fundamental Forecast. Duke Energy did however utilize other third party forecasts in the validation process to verify the reasonableness of the Duke Energy outlook and to help set the appropriate range for fuel price sensitivities.

c. Please identify each difference in DEF's fuel forecast methodology used in this docket when compared to: 1) the Company's most recent rate case, 2) the Company's Ten Year Site Plan filed in 2014 and 3) the company's methodology used in Docket No. 130200-EI.

<u>**RESPONSE**</u>:

DEF's most recent rate case was in 2009 and in that docket only a one year projection was provided which had been developed in late 2008. The forecast methodology used in 2008 relied on forecasts from two industry recognized consultants PIRA and Global Insight, DEF used a numerical average of the two. The forecast used in this docket is considerably different that the one constructed in 2008, but that has less to do with the methodology than the significant changes to the energy industry over the past six years. At that time, neither the full effects of the new technologies in unconventional gas development, nor the full impacts of the recession, were known. Gas prices were projected to be above $8 (2008$) for the foreseeable future, and coal prices were supported by higher load and lack of competition from inexpensive gas. In the longer term, at that time, a carbon emission price of $25 - $50 per ton was anticipated beginning in the 2014 - 2016 timeframe which would depress the long term price of coal and further inflate the price of gas. The methodology described in part a) is now used in all Duke Energy jurisdictions and the resulting forecast is consistent with the long term outlook for the company. The same fuel price forecast used in this docket was also used in the company's Ten Year Site Plan filed in 2014 as well as Docket No. 130200-EI.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of July, 2014, 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) 1 through 25, 28, 33 through 35, 53(i-j), 54 and 55c from FLORIDA PUBLIC SERVICE COMMISSION STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-55) in Docket No. 140111-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Sandra L Brice
Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

35427963.1

AFFIDAVIT

STATE OF MASSACHUSETTS)

COUNTY OF BARNSTABLE)

I hereby certify that on this 8th day of July, 2014, before me, an officer duly authorized in Massachusetts to take acknowledgments, personally appeared Julie Solomon, who is personally known to me or has provided identification, and has acknowledged before me that she provided the answers to interrogatory number(s) 39 through 52 from FLORIDA PUBLIC SERVICE COMMISSION STAFF'S FIRST SET OF INTERROGATORIES NOS. 1-55 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal as of this 8th day of July, 2014.

Julie R. Solomon

Julie R. Solomon

Janet H. Daley

Notary Public

My Commission Expires:
06/03/2016

JANET H. DALEY
NOTARY PUBLIC
Commonwealth of Massachusetts
My Commission Expires
June 3, 2016

AFFIDAVIT

STATE OF ~~FLORIDA~~ North Carolina

COUNTY OF ~~PINELLAS~~ Mecklenburg

I hereby certify that on this 15th day of July, 2014, 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 responses to interrogatory number(s) 26, 27, 29 through 32, and 34 through 38 from STAFF'S FIRST INTERROGATORIES NOS. 1-55 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-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 15th day of July, 2014.

MURIEL R. SPEAR
NOTARY PUBLIC
Mecklenburg County
North Carolina
My Commission Expires ______

Mark E. Landseidel

Muriel Spear
Notary Public
State ~~of Florida~~, at Large North Carolina

My Commission Expires:
October 29, 2018

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 15th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kevin Delehanty, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory number(s) 53a-53h and 55a-55b from STAFF'S FIRST INTERROGATORIES NOS. 1-55 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-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 15th day of July, 2014.

Kevin Delehanty

Kevin Delehanty

Nancy H. Taylor

Notary Public
State of Florida, at Large

NANCY H. TAYLOR NOTARY PUBLIC MECKLENBURG COUNTY, NC

My Commission Expires:
January 26, 2017

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 14th day of August, 2014, 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 revised response to interrogatory number 30 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 55 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 14th day of August, 2014.

Mark E. Landseidel

Notary Public
State of ~~Florida~~, at Large
North Carolina

My Commission Expires:
October 20, 2018

102

DEF's responses to Staff's Second Set of Interrogatories, Nos. 56-61

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 102
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Second Set of Interrogatories, Nos. 56-61.
[Bates Nos. 00207-00214]

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 Served: July 23, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 56-61)

Duke Energy Florida, Inc. ("DEF") responds to Staff of the Florida Public Service Commission ("Staff") Second Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 56-61) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's Second Set of Interrogatories (Nos. 56-61), served on July 18, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

56. Please identify all the filings, docketed and undocketed, at the Florida Public Service Commission containing the same fuel price forecast as DEF's Fundamental Forecasts used in developing its base case in this proceeding.

RESPONSE:

DEF used the same fuel price forecast in this docket, Docket No. 140110, Docket No. 130200-EI, and the Ten Year Site Plan Filing in 2014.

57. Please identify the dates when DEF's short term and long term fuel price forecasts provided as the fuel price input to DEF's base case in this proceeding were begun and completed and the major milestones from start to finish.

RESPONSE:

The DEF long term fundamental forecast used in this filing was considered a Fall update to the 2013 Duke Long Term Fundamental Forecast which was completed in the Spring of 2013. The justification for updating the Duke outlook in the Fall of 2013 was primarily due to EVA's new reserve estimates for natural gas which were the result of new data from the US Potential Gas Committee report published in April 2013. The timeline began with EVA delivering the initial sections of their Fall 2013 outlook (dubbed "Fuelcast") on 9/6/2013 and then EVA continued to send additional sections of the forecast throughout the month of September 2013. Duke reviewed the EVA forecast sections as they received them and immediately began outlining the requested assumption changes to be used in the development of the Duke outlook. The review process and assumption changes occurred primarily during the month of September 2013. EVA then re-ran their models and began producing initial results in early October 2013 and delivered the final components of the Duke Energy 2013 Fall Refresh forecast on 10/22/2013. The validation of the Fall update to the 2013 Duke Energy Fundamental Forecast began in October 2013 and was completed in early November 2013. The Short Term fuel price forecast is based on a snapshot of "futures market" price quotes on the New York Mercantile Exchange (NYMEX) on 10/18/2013, and the transportation cost estimates were updated on 12/31/2013.

58. If the level of CO_2 emissions regulations assumed by DEF in preparing its Fundamental Forecast as discussed in witness Delehanty's direct testimony, page 11 is less or more restrictive than the regulations reflected in the U.S. EPA 6/2/14 Clean Power Proposal, what are the expected impacts on fuel prices relative to DEF's Fundamental Forecast provided in this proceeding?

RESPONSE:

Duke Energy has not yet evaluated the potential impact of the EPA's Clean Power Proposal on fuel prices. The proposed rule as currently structured, requires each state to submit a state level implementation plan (SIP) to the EPA which will achieve the targeted emissions rate by 2030 (or earlier at a higher target rate). Given the complexity of the proposed rule and the various avenues the individual states may choose, it is difficult to assess what the impact will be on the aggregate demand for natural gas in the United States relative to the assumptions used in the 2013 Fall update to the Duke Energy forecast which included a national carbon tax.

59. What were the contemporary, well-recognized industry natural gas price forecasts (forecasts source and fuel price data) DEF used to compare to its Fundamental Forecast referenced in witness Delehanty's direct testimony, page 11, lines 19-22?

RESPONSE:

Duke Energy used the following natural gas price forecasts:

a. **Wood Mackenzie Fall 2013 Long Term View**

b. **PIRA October 2013 Long Term Outlook**

c. **EVA Fall 2013 Long Term Outlook**

d. **EVA Fall 2013 C02 Sensitivity to the Long Term Outlook**

e. **ESAI Fall 2013 Long Term Base Case**

f. **Energy Information Agency 2013 Annual Energy Outlook**

g. **BENTEK Fall 2013 Reference Case for the MISO Transmission Owners Group**

60. Provide the calculations and data showing the development of the "statistically relevant deviations to the data" used to compare DEF's Fundamental Forecast to other natural gas price forecasts as referenced in witness Delehanty's direct testimony, page 11, lines 19-22.

<u>**RESPONSE**</u>:

Please see the confidential workbook entitled "Fall_2013_gas price_sensitivities.xlsx" produced in Bates range 14LGBRA-STAFFROG2-60-000001. This document is confidential and subject to DEF's Fourteenth Notice of Intent filed contemporaneously with the service of this response.

61. Please describe each of the changes and assumptions broadly identified in witness Delehanty's direct testimony, page 9, lines 5-18, (e.g. "coal plant retirement assumptions for existing coal plants") which DEF made to the EVA Fundamental Forecast.

RESPONSE:

Duke Energy reviewed the list of early coal plant retirements submitted by EVA and compared it to previous lists of coal retirements assumed by Duke Energy in prior forecasts. EVA used an economic standard as well as an age limitation in determining their assumed candidates for retirement. In prior fundamental forecasts, Duke Energy screened coal units by analyzing whether the units would generate sufficient economic margin to cover the required capital expenses associated with installing the necessary environmental controls. The types of "necessary" controls were determined by meeting an equipment based standard of compliance with MATS, CSAPR, 316b, and CCR. Where the two methodologies came to different conclusions on a particular unit, Duke Energy looked to available public disclosures offered by the owner of the coal unit to decide whether to assume a coal retirement or not. The differences in net coal generation were not very large as most of the coal units were either small in size and/or they ran at low capacity factors. In total, EVA assumed the early retirement of 527 coal units representing 72,280 MW's of capacity (nameplate ratings). Duke Energy assumed 488 coal units retire early, representing 66,329 MW's of capacity (nameplate ratings). Please see the confidential workbook entitled: "Retirements Final.xlsx" produced in Bates range 14LGBRA-STAFFROG2-61-000001. This document is confidential and subject to DEF's Fourteenth Notice of Intent filed contemporaneously with the service of this response.

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 22nd day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kevin Delehanty, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory numbers 56-61 from STAFF'S SECOND INTERROGATORIES NOS. 56-61 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-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 22nd day of July, 2014.

Kevin Delehanty

Nancy H. Taylor

Notary Public

State of North Carolina, at Large

NANCY H. TAYLOR
NOTARY
PUBLIC
MECKLENBURG COUNTY, NC

My Commission Expires:

January 26, 2017

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DEF's responses to Staff's Third Set of Interrogatories, Nos. 62-83

<u>See also</u>: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 103
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Third Set of Interrogatories, Nos. 62-83. See also files contained on Sta...

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 Served: August 12, 2014

REDACTED
DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S
THIRD SET OF INTERROGATORIES TO (NOS. 62-83)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Third Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 62-83) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Third Set of Interrogatories (Nos. 62-83), served on August 4, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

62. On page 45 of witness Benjamin Borsch's testimony, the witness states that the cost of the upgrades to provide an additional 600 MW to 800 MW of transmission import capacity would be "in the realm of hundreds of millions of dollars." To the extent possible please provide projected range of the described costs (i.e. $100 million to $200 million). Furthermore please provide the factual basis for your answer.

RESPONSE:

DEF transmission planning performed a screening study to evaluate the requirement to increase DEF's Simultaneous Import Capability (SIL) by 600 - 1000 MW from neighboring Florida (FRCC) Utilities over the current capability. This study indicated that this increase would lead to a need to rebuild more than 60 miles of 230 kV lines, with corresponding upgrade work at the terminating substations at a cost of $100 million - $200 million.

63. Has DEF had an opportunity to evaluate/analyze Calpine's July 2014 offer as described on pages 7-10 of Calpine witness Thornton's testimony.

a. If yes, please provide the results of evaluation/analysis (including all economic evaluations).

REDACTED

<u>RESPONSE</u>:

[redacted]

Details of this analysis can be found in Exhibit BMHB-18 to the rebuttal testimony of Mr. Benjamin Borsch.

b. If no, does DEF plan to evaluate/analyze Calpine's July 2014 offer?

- If no, please explain why not.

<u>RESPONSE</u>:

N/A.

c. If no, does DEF believe that one of its existing analyses (i.e. the Company's initial detailed economic evaluation) provides a comparable evaluation?

- If yes, please identify which one.

<u>RESPONSE</u>:

N/A.

64. Regarding Acquisition_PPA Mix 1, as identified in Exhibit BMHB-10, please state the assumed term of the Purchased Power Agreement (PPA) and the assumed date of the Acquisition.

<u>RESPONSE</u>:

Regarding Acquisition_PPA Mix 1, as identified in Exhibit BMHB-10, the assumed term of the PPA is 4/1/2016 to 3/21/2021 and the Acquisition starts on 1/1/2015.

Note that the acquisition considered in Mix 1 and Mix 2 is not one of the acquisitions considered as Acquisition 1 or Acquisition 2, but rather a smaller acquisition that did not meet DEF's MW needs on its own and thus needed to be paired with a PPA. The Mix alternatives did not contemplate the structure of deal where a PPA was followed by an acquisition, as no offers of that type had been received at the time of the evaluation.

65. Regarding Acquisition_PPA Mix 2, as identified in Exhibit BMHB-10, please state the assumed term of the PPA and the assumed date of the Acquisition.

<u>RESPONSE</u>:

Regarding Acquisition_PPA Mix 2, as identified in Exhibit BMHB-8, the assumed term of the PPA is 4/1/2016 to 3/21/2021 and the Acquisition starts on 1/1/2015. Acquisition_PPA Mix 2 was not included in Exhibit BMHB-10.

66. Regarding Acquisition_PPA Mix 1, as identified in Exhibit BMHB-10, please identify which Acquisition was assumed (i.e. Acquisition 1) and which PPA was assumed (i.e. PPA 1)

RESPONSE:

Acquisition_PPA Mix 1 assumes PPA2 and an Acquisition that is not one of the other individual Acquisitions evaluated.

The capacity of the Acquisition is 143MWs (summer only).

67. Regarding Acquisition_PPA Mix 2, as identified in Exhibit BMHB-10, please identify which Acquisition was assumed (i.e. Acquisition 1) and which PPA was assumed (i.e. PPA 1)

RESPONSE:

Acquisition_PPA Mix 2 was included in Exhibit BMHB-8, not in Exhibit 10.

Acquisition_PPA Mix 2 assumes PPA1 and an Acquisition that is not one of the other individual Acquisitions evaluated.

The capacity of the Acquisition is 143MWs (summer only).

68. Were any FERC mitigation costs considered in DEF's evaluation of Acquisition_PPA Mix 1?

a. If yes, what was the total amount of those costs?

RESPONSE:

N/A.

b. If no, why did DEF believe FERC mitigation costs were not relevant in the Company's evaluation of Acquisition_PPA Mix 1?

RESPONSE:

DEF did not evaluate the potential FERC mitigation costs associated with the Acquisition_PPA Mix options evaluated because the options were not shown to be cost effective compared to the base case and did not have potential sensitivity "upside" that would have made them cost effective compared to the base case. As a result, these options were not considered for further evaluation regardless of the FERC mitigation results.

In general, DEF did not believe that significant FERC mitigation costs would apply in the context of the Acquisition_PPA Mix 1 because the acquisition was small and seasonal in capacity.

69. DEF's response to staff interrogatory No. 4, states that the Company's "transmission analysis showed that retiring the steam units at the time of commercial operation of the peakers in 2016 would avoid the need for significant transmission upgrades, reducing the transmission upgrade costs from approximately $70 million to the forecast $15.7 million." Could the same savings ($70 million to the forecast $15.7) be realized if the steam unites are retired in 2018 and the commercial operation of the peakers begins in 2018?

RESPONSE:

The $70 million cost was based on the assumption that the peakers and the steam units were in service at the same time. Since the steam units are expected to retire in 2018 at the latest, the $70 million cost would not apply in the case where the peakers did not come into service until 2018.

70. Has DEF sought a statement from the FERC regarding the impact on market power if DEF purchasing the Osceola Facility?

RESPONSE:

No.

a. If yes, please provide FERC's response.

RESPONSE:

N/A.

b. If no, why not?

RESPONSE:

DEF has not sought a statement from FERC regarding the impact on market power if DEF purchased the Osceola Facility. This is because FERC does not provide advisory opinions or declaratory statements. There is no formal process to obtain a statement from FERC about the impact of a particular acquisition on market power until the application is submitted and FERC rules on the application. A potential applicant can meet with FERC staff, but only before an application is filed with FERC, and any discussions with Staff likely will yield no definitive answers regarding how FERC will ultimately rule and certainly are not binding on FERC.

71. Has DEF sought a statement from the FERC regarding the impact on market power if DEF purchasing the Osprey Energy Center?

RESPONSE:

No.

a. If yes, please provide FERC's response.

RESPONSE:

N/A.

b. If no, why not?

RESPONSE:

DEF has not sought a statement from FERC regarding the impact on market power if DEF purchased the Osprey Energy Center. This is because FERC does not provide advisory opinions or declaratory statements. There is no formal process to obtain a statement from FERC about the impact of a particular acquisition on market power until the application is submitted and FERC rules on the application. A potential applicant can meet with FERC staff, but only before an application is filed with FERC, and any discussions with Staff likely will yield no definitive answers regarding how FERC will ultimately rule and certainly are not binding on FERC.

72. On pages 38 of witness Borsch's testimony, the witness states that imputed debt was found to be less than \$5 million and was deemed not to be material in the results. NRG witness Jeffrey Pollock, on pages 12 and 13 of his testimony, appears to testify that consideration of imputed debt ranged from \$175 million to \$562 million NPVRR. Please clarify the impact of imputed debt on DEF's economic analysis.

RESPONSE:

It is not clear to DEF what Mr. Pollock is referring to in his direct testimony. The range of imputed debt that he refers to in his direct testimony is not from the quantitative analyses DEF performed to determine the most cost effective generation alternative to meet DEF's need prior to 2018. In that evaluation of resources prior to 2018, the alternatives considered were short term (up to 5 year) PPAs and acquisitions. As stated in the direct and rebuttal testimony of Mr. Borsch in Docket No. 140111-EI, DEF concluded that imputed debt was not material to either of these transactions and therefore was not considered in that evaluation.

73. Please complete the table below summarizing DEF's projected generation additions and retirements assuming the Company's current expansion plan. Please include summer capacity values for each addition and retirement.

	Generation Additions	Generation Retirements
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
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2035		
2036		
2037		
2038		
2039		
2040		
2041		

RESPONSE:

DEF's projected generation additions and retirements in the Company's proposed expansion plan.

	Generation Additions	MWs	Generation Retirements	MWs
2014	Orlando Cogen Additional Capacity	36	Lake County Contract Expires Turner 3 Retires	13 53
2015				
2016	Orange County Additional Capacity Southern Franklin Contract Suwannee CTs	30 425 316	Crystal River 1 Deration Crystal River 2 Deration Turner 1 Retirement Turner 2 Retirement Rio Pinar Retirement Avon Park 1 Retirement Avon Park 2 Retirement Southern Scherer Contract Expires Southern Franklin Contract Expires Suwannee Steam Units Retirement	50 79 10 10 12 24 24 71 342 128
2017	Hines 1-4 Inlet Chillers Uprate	220		
2018	Citrus Combined Cycle	1640	Crystal River 1 Retirement Crystal River 2 Retirement	320 420
2019				
2020			Higgins 1 Retirement Higgins 2 Retirement Higgins 3 Retirement Higgins 4 Retirement	20 25 30 30
2021	Combined Cycle 2x1	793	Southern Franklin Contract Expires	425
2022				
2023			Orlando Contract Expires	115
2024	Combined Cycle 2x1	793	Shady Hills Contract Expires Mulberry Contract Expires	476 115
2025			Orange County Contract Expires	104
2026	Simple Cycle	187		
2027	Combined Cycle 2x1	793	Vandolah Contract Expires	639
2028				
2029	Simple Cycle	187		
2030	Simple Cycle	187		
2031				
2032	Simple Cycle	187		
2033				
2034	Simple Cycle	187	Florida Power Development Biomass	60
2035				
2036	Combined Cycle 2x1	793		

2037				
2038				
2039				
2040				
2041				

74. Assuming approval of the proposed projects, what does DEF anticipate the base rate increase would be when the proposed projects are placed in service?

RESPONSE:

DEF estimates a residential base rate increase of approximately $1.39 on a 1,000 kWh bill.

75. Does DEF anticipate seeking a base rate increase at the time the Suwannee Simple Cycle project and the Hines Chillers Power Uprate Project are placed in service (i.e. 2017) or at the time each unit is placed in service (i.e. 2016 and 2017)?

RESPONSE:

DEF anticipates seeking a base rate increase consistent with the provisions of the 2013 Revised and Restated Settlement Agreement in advance of the commercial in service date(s) such that the Commission has time to review and approve DEF's request and implementation can occur with the first billing cycle following the commercial in-service of the respective unit/uprate(s).

76. Are the financial forecasts and assumptions used in Docket No. 140111 the same as those used in Docket No. 140110?

a. If no, please identify the different assumption or forecast and explain the reason for the difference.

RESPONSE:

Yes, the forecasts and assumptions used in Docket No. 140111 and Docket No. 140110 are the same.

77. On pages 40-41 of witness Borsch's testimony, the witness states that the Hines Chillers made projects more favorable from a CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. Please provide a range of savings (in 2014 dollars) associated with including the Chillers when they were not needed for reliability purposes.

RESPONSE:

The analysis of the Hines Chillers in the acquisition cases show that they provide savings between $90M to $140M (in 2014$). Resource Plans without the Hines Chillers add a generic Combustion Turbine (CT) later in the planning period to meet reserve margin. Although the early addition of the Hines Inlet Chillers increases capital costs, they have a more efficient heat rate compared to the one from a new generic CT which reduces fuel and emissions costs. In addition to that, the timing and location of the Hines Chillers provides gas reservation charges savings as well.

78. On pages 40-41 of witness Borsch's testimony, the witness states that the Hines Chillers made projects more favorable from a CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. Did DEF evaluate resource plans that combined the Chillers and a PPA/Acquisition (or combination of both) without the proposed Suwannee CTs?

RESPONSE:

Yes, all the Resource Plans with PPAs or Acquisitions in Exhibits BMHB-8 and BMHB-10 include Chillers and do not include Suwannee CTs.

The only exception is the Resource Plan with PPA1 in Exhibits BMHB-8 that has just one Suwannee CT.

a. If yes, please provide CPVRR results of these analyses.

RESPONSE:

Ref. Exhibit BMHB-8

Cumulative PV Revenue Requirements Comparison Acquisition Options								
$M 2013	PPA2	PPA3	ACQ2	ACQ1	ACQ PPA MIX1	ACQ PPA MIX2	ACQ3	ACQ4
Capital Costs	4,575	4,575	4,714	4,461	4,564	4,564	4,642	4,700
Fuel	32,400	32,478	32,591	32,525	32,552	32,283	32,534	32,544
Emissions	7,755	7,760	7,850	7,826	7,782	7,764	7,766	7,778
Variable Costs	2,180	2,185	2,063	2,142	2,180	2,166	2,177	2,175
Fixed Costs	8,650	8,650	8,676	8,690	8,657	8,657	8,837	8,878
PPAs	1,953	1,858	1,639	1,673	1,746	2,055	1,674	1,681
Cogens	6,340	6,339	6,381	6,354	6,344	6,346	6,344	6,343
Emergency Energy	4	6	2	4	4	4	4	8
Total	63,858	63,851	63,916	63,674	63,829	63,839	63,977	64,108

Ref. Exhibit BMHB-10

[illegible]		
[illegible]	[illegible]	[illegible]
Capital Costs	5,089	5,094
Fuel	34,296	34,095
Emissions	8,649	8,632
Variable Costs	2,209	2,198
Fixed Costs	9,043	9,031
PPAs	1,675	1,891
Cogens	4,674	4,672
Emergency Energy	9	9
Total	65,643	65,621

b. If no, please explain why not.

RESPONSE:

N/A.

c. If no, please provide a CPVRR analysis, consistent with the one presented in exhibit BMHB-10, comparing the most cost-effective resource plan (that meets DEF's reliability requirements) that combines the Chillers and a PPA/Acquisition (or combination of both) and DEF's proposed resource plan.

RESPONSE:

N/A.

79. Please complete the table below summarizing the revenue requirements for Acquisition 1 and Acquisition 2. Please provide this information based on the assumptions used in DEF's Initial Detailed Economic Analysis (presented in Exhibit No. BMHB-8). Please provide this information in electronic format (excel).

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
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2043								
2044								
2045								
2046								

	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2047								
2048								
2049								
2050								
Total								

RESPONSE:

Acquisition 1								
	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month
2014	9	-	107	1,738	29	354	2,238	$ 0.19
2015	15	0	123	1,709	38	339	2,224	$ 0.52
2016	13	3	103	1,664	38	344	2,165	$ 0.20
2017	23	4	89	1,745	36	335	2,232	$ (0.18)
2018	83	4	83	1,865	19	327	2,382	$ (0.07)
2019	174	4	78	1,910	15	319	2,500	$ 0.15
2020	158	3	81	1,931	310	312	2,795	$ (0.25)
2021	191	23	91	1,892	315	284	2,796	$ (0.12)
2022	204	34	98	1,848	319	264	2,766	$ 0.27
2023	186	31	95	1,794	329	259	2,693	$ 0.18
2024	202	34	101	1,728	330	185	2,581	$ 0.01
2025	206	35	103	1,698	332	94	2,467	$ 0.56
2026	187	32	99	1,649	341	54	2,363	$ (0.07)
2027	207	45	105	1,611	343	43	2,354	$ 0.39
2028	213	52	107	1,574	344	33	2,323	$ 0.18
2029	194	47	103	1,519	354	31	2,249	$ (0.85)
2030	176	43	100	1,478	364	30	2,191	$ (0.86)
2031	163	40	97	1,438	372	29	2,140	$ (0.93)
2032	151	37	95	1,413	384	28	2,107	$ (0.54)
2033	140	35	91	1,372	391	27	2,055	$ (0.22)
2034	129	32	90	1,333	391	25	2,000	$ (2.77)
2035	120	30	87	1,295	394	24	1,950	$ (3.54)
2036	110	28	84	1,255	397	23	1,898	$ (2.92)
2037	102	26	82	1,216	393	22	1,843	$ (2.03)
2038	94	24	79	1,175	397	21	1,791	$ (1.85)
2039	103	26	79	1,133	392	20	1,753	$ 0.48
2040	106	25	79	1,102	388	19	1,719	$ 2.74
2041	96	23	76	1,062	392	18	1,667	$ 2.30
2042	87	21	74	1,023	396	17	1,617	$ 1.70
2043	81	19	71	991	397	17	1,576	$ 2.07

Notes:
* Residential bill impact displayed as a differential from Self Build base case. 1,200 kWh/month rate based on average residential price.

*Chart reflects preliminary/initial values only.

Acquisition 2									
	Annual Revenue Requirements (Generation Capital) ($millions, 2014 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2014 $)	Annual Revenue Requirements (O&M) ($millions, 2014 $)	Annual Revenue Requirements (Fuel) ($millions, 2014 $)	Annual Revenue Requirements (Environmental) ($millions, 2014 $)	Other ($millions, 2014 $)	Total ($millions, 2014 $)	Impact on Residential Bill for 1,200 kWh/month	
2014	26	-	110	1,731	28	362	2,257	$	0.95
2015	41	0	127	1,696	37	352	2,252	$	1.69
2016	37	3	106	1,653	37	356	2,192	$	1.36
2017	45	4	92	1,732	35	346	2,254	$	0.84
2018	103	21	86	1,854	19	338	2,420	$	1.51
2019	192	30	80	1,895	14	329	2,541	$	1.85
2020	174	27	84	1,922	304	322	2,834	$	1.44
2021	164	26	83	1,883	317	293	2,766	$	(1.64)
2022	157	26	83	1,834	323	272	2,696	$	(3.32)
2023	146	25	81	1,789	335	267	2,642	$	(2.56)
2024	175	41	89	1,719	338	193	2,555	$	(1.61)
2025	186	49	92	1,684	339	101	2,451	$	(0.57)
2026	174	46	88	1,643	351	61	2,363	$	(0.28)
2027	190	48	95	1,607	349	47	2,335	$	(0.93)
2028	192	47	96	1,567	352	39	2,293	$	(1.90)
2029	174	43	93	1,517	363	38	2,228	$	(2.40)
2030	191	53	96	1,479	364	36	2,220	$	1.38
2031	196	58	98	1,450	368	34	2,204	$	4.18
2032	177	52	95	1,413	381	32	2,151	$	3.21
2033	161	48	91	1,373	390	31	2,093	$	3.13
2034	146	43	90	1,335	388	29	2,032	$	0.26
2035	132	39	87	1,293	392	28	1,972	$	(1.43)
2036	120	36	85	1,256	394	27	1,916	$	(0.99)
2037	108	33	83	1,214	390	26	1,854	$	(0.88)
2038	98	30	79	1,170	395	25	1,797	$	(1.18)
2039	106	30	79	1,131	393	22	1,761	$	1.39
2040	107	30	79	1,100	389	19	1,723	$	3.22
2041	100	28	76	1,062	392	18	1,675	$	3.35
2042	92	26	74	1,023	396	17	1,627	$	3.09
2043	86	24	71	991	397	17	1,586	$	3.40

Notes:
* Residential bill impact displayed as a differential from Self Build base case. 1,200 kWh/month rate based on average residential price.
*Chart reflects preliminary/initial values only.

See also excel spreadsheets bearing Bates Nos. 14LGBRA-STAFFROG3-79-000001 through 14LGBRA-STAFFROG3-79-000002.

80. What is the average net operating heat rate of the Suwannee Steam units?

RESPONSE:

Unit	Average Net Operating Heat Rate (Years: 2011, 2012, 2013) Btu/Kwh
Suwannee Steam Unit 1	14,708
Suwannee Steam Unit 2	14,879
Suwannee Steam Unit 3	11,837

81. For the purposes of the following interrogatory, please refer to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-2, Page 18 of 76. This exhibit presents DEF's Base "History and Forecast of Summer Peak Demand – Base Case."

a. Please provide the Company's High Case, and Low Case forecast Summer Peak Demand.

RESPONSE:

DEF does not have a High Case and Low Case forecast for Summer Peak Demand. The Company uses a robust load forecasting methodology which examines forecasts of economic growth and historic weather and customer usage. Given the detailed analysis used to develop the load forecast, the Company determined that sensitivities would not yield markedly different results.

b. Please provide the factual basis for how the High Case and Low Case Forecasts were developed.

RESPONSE:

DEF does not have a High Case and Low Case forecast for Summer Peak Demand.

82. For the purposes of the following interrogatory, please refer to the Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-2, Page 19 of 76. This exhibit presents DEF's Base "History and Forecast of Winter Peak Demand – Base Case."

a. Please provide the Company's High Case and Low Case forecast of Winter Peak Demand.

<u>RESPONSE</u>:

DEF does not have a High Case and Low Case forecast for Winter Peak Demand. The Company uses a robust load forecasting methodology which examines forecasts of economic growth and historic weather and customer usage. Given the detailed analysis used to develop the load forecast, the Company determined that sensitivities would not yield markedly different results.

b. Please provide the factual basis for how the High Case and Low Case Forecasts were developed.

<u>RESPONSE</u>:

DEF does not have a High Case and Low Case forecast for Winter Peak Demand.

83. Please complete the two charts below. Staff is seeking DEF's Summer and Winter Peak Demand Forecasts accuracies (error in percentage terms) for the years 2009 - 2013. The "Forecast Development Year" axis displays the years in which the forecast was made. The "*Forecasted Years*" axis displays the years being forecasted. Please also provide a brief explanation of what the Company believes led to error rate.

a. Summer

Forecast Development Year	*FORECASTED YEARS* *2010*	*2011*	*2012*	*2013*
2009				
2010				
2011				
2012				

b. Winter

Forecast Development Year	*FORECASTED YEARS* *2010*	*2011*	*2012*	*2013*
2009				
2010				
2011				
2012				

<u>RESPONSE:</u>

a **Summer: The summer forecasted accuracy table is shown below:**

	FORECASTED YEARS			
Forecast Development Year	*2010*	*2011*	*2012*	*2013*
2009	-3.1%	-4.8%	-7.1%	-10.9%
2010		-3.4%	-4.9%	-8.5%
2011			-5.1%	-5.2%
2012				-7.6%

The summer peak demand forecast variances are attributed to an unusually weak economic recovery from the Great Recession, including the associated prolonged recovery of the Florida housing market. Annual forecast input assumptions from Moody's Analytics and the University of Florida's Bureau of Economic & Business Research contributed to these variances as well since they were constantly revised during this period due to changing projections of Florida economic activity or population growth over time.

b. **Winter: The winter forecasted accuracy table is shown below:**

	FORECASTED YEARS			
Forecast Development Year	*2010*	*2011*	*2012*	*2013*
2009	2.9%	-9.8%	-25.2%	-24.3%
2010		-5.5%	-20.2%	-18.4%
2011			-18.1%	-13.5%
2012				-11.5%

The winter peak demand forecast variances are attributed to an unusually weak economic recovery from the Great Recession, including the associated prolonged recovery of the Florida housing market. Annual forecast input assumptions from Moody's Analytics and the University of Florida's Bureau of Economic & Business Research contributed to these variances as well since they were constantly revised during this period due to changing projections of Florida economic activity or population growth over time.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 21st day of August, 2014, 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 62-83 from STAFF'S THIRD SET OF INTERROGATORIES (Nos. 62-83) in Docket No(s). 140111-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 21st day of August, 2014.

Benjamin M.H. Borsch

Sandra C...

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

104

DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 84-86

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 104
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Fourth Set of Interrogatories, Nos. 84-86. [Bates Nos. 00245-00250]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Citrus County combined cycle power plant, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI DATED: August 12, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 84-86)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fourth Set of Interrogatories (Nos. 84-86) to Duke Energy Florida, Inc. as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Fourth Set of Interrogatories Nos. 84-86, served on August 7, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

84. In response to staff interrogatory No. 2, DEF states that it has not recently performed an evaluation of cost-effectiveness of keeping Avon Park, Rio Pinar, and Turner P1 and P2 in service. When was the last evaluation of cost-effectiveness performed? Please provide a summary of the results of the last evaluation of cost-effectiveness.

RESPONSE:

DEF began evaluating the cost-effectiveness of keeping these units in service in 2008, and since that time, the factors discussed below that were used in that analysis continue to support DEF's planned retirement strategy.

The Combustion Turbines (CTs) noted above are 1968 to 1970 vintage units that burn mainly distillate oil, are around 45 years old, have heat rates ranging from 15,300 to 18,800 btu/kwh, and have individual summer capacities ranging from 10 to 24 MW. Presently, the estimated oil dispatch cost of these CT units are sometimes up to ten times more expensive to dispatch versus natural gas-fired generation. In the 2014 TYSP, DEF confirms that it does not believe that these small, old, inefficient CTs are a strategic fit in operating a safe, reliable, clean, economical and

efficient peaking fleet and should be retired when efficient and reliable replacement resources are available in 2016.

Due to the advanced age of these units, DEF has been forced to rely on second-hand/salvage equipment suppliers and component remanufacturers (see Response to Q86) to keep the units available in case they were needed to support the grid. DEF acknowledges that this capacity is becoming increasingly difficult to maintain at a desired level of availability to serve firm load for the long-term.

85. Please define the term "cold stand-by" as it is used on page 11 of Exhibit No. BMHB-2.

RESPONSE:

DEF uses the term "cold stand-by" to reflect that the unit has been placed in long-term shut-down mode through-out the planning horizon and the ultimate unit retirement is dependent, in part, of accomplishing the overall 2014 TYSP resource plan.

86. In response to staff interrogatory No. 2, DEF states that Avon Park, Rio Pinar, and Turner P1 and P2 were originally identified during the 2008 planning cycle for retirement in 2016 based on the age of the equipment and the limited availability of replacement parts. Please discuss any reliability issues DEF has experienced in the last five years at Avon Park, Rio Pinar, and Turner P1 and P2.

RESPONSE:

DEF continually performs operation and maintenance surveillance to identify or correct reliability concerns on these units. DEF has experienced control equipment replacement part issues, turbine expander end of life concerns, turbine and compressor blade wear and fatigue concerns, generator and transformer protection and control concerns as well as fuel handling equipment concerns over the past 5 years. DEF has had difficulty in finding certain key components and has had to revert to secondary sources (salvage part suppliers, parts remanufacturers, E-Bay, etc.) to find the necessary spare parts. Using these secondary sources for limited supply options leaves DEF dependent on these suppliers remaining in business to support the equipment.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 21st day of August, 2014, 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 84 through 86 from STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 84-86) in Docket No(s). 140111-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 21st day of August, 2014.

Benjamin M.H. Borsch

Sandra Cope

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

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105

DEF's responses to Staff's Fifth Set of Interrogatories, Nos. 87-90

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 105
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Fifth Set of Interrogatories, Nos. 87-90. [Bates Nos. 00251-00257]

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 20, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 87-90)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fifth Set of Interrogatories (Nos. 87-90) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Fifth Set of Interrogatories Nos. 87-90, served on August 18, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

87. On page 3 of Witness Patton's rebuttal testimony, the witness states that he filed direct testimony in Docket No. 140110-EI regarding the natural gas transportation and supply for the Citrus County Combined Cycle Power Plant. Please describe how the delay or cancellation of the Sabal Trail natural gas pipeline would impact DEF's proposed Suwannee CTs as well as DEF's proposed Citrus County Combined Cycle Power Plant.

RESPONSE:

A delay or cancellation of the Sabal Trail natural gas pipeline would not impact DEF's proposed Suwannee CTs as it is served off of Florida Gas Transmission.

With respect to Sabal Trail, given current project timelines, commenced project activities by Sabal Trail, and the critical nature of the project to meet the needs of multiple customers in the State of Florida, a significant project delay or cancellation is not reasonably expected. An unlikely cancellation would have broader impacts to the State and other customers such as Florida Power & Light Company ("FPL") given the critical nature of the project to support overall needs in the State. In summary, unanticipated project in-service delays are managed through the existing

project management and the project teams would work closely with Sabal Trail to mitigate risks. In the unlikely event of a cancellation, DEF and other parties would have to begin the process to evaluate new options at some unknown future date of a hypothetical cancellation. Sabal Trail, however, commenced project execution years in advance to ensure project plans can be executed and to ensure gas transportation needs in the future are met by the target in-service date.

Both DEF and FPL have contracted for firm gas transportation service on Sabal Trail. DEF has contracted with Sabal Trail for the Citrus County Combined Cycle Power Plant. DEF's contractual target in-service date for Sabal Trail is October 1, 2017 to support the start-up and commissioning of the Citrus County Combined Cycle Power Plant before the planned commencement of operation of the plant. In addition, FPL has contracted with Sabal Trail for firm gas transportation with an in-service date of May 1, 2017 that is five months prior to DEF's October 1, 2017 in-service date. Given these critical commitments by Sabal Trail to support the needs of both FPL and DEF, Sabal Trail has allowed an approximate four year lead time to execute the project and complete needed milestones which include obtaining its FERC certificate and authorizations, and completing the construction necessary to be in-service to meet the critical service commitments. Both DEF and FPL have contractual provisions that provide for some compensation in the event of a project delay. There currently is no reasonable basis to expect a delay much less a cancellation of the Sabal Trail pipeline.

88. On page 12 of Witness Patton's rebuttal testimony, the witness states that "During peak load periods shippers will not be releasing gas transportation capacity into the market or if they do it will be at a higher price." Please describe in detail how DEF ensures, or reasonably plans, that it will have sufficient gas transportation capacity to generate its natural gas units during peak load periods?

<u>**RESPONSE**</u>:

As part of its on-going planning process to ensure that DEF has sufficient gas supply and transportation capacity to meet its current and future gas generation needs. DEF reviews periodic forecasted fuel burns, existing transportation agreements, and new generation plans to determine the volume of new transportation that is needed to reliable support its current and future generation facilities. Based on this review, DEF has acquired firm transportation service that provides access to needed supply points and delivery to its generation facilities to meet its overall peaking load requirements.

89. On page 20 of Witness Patton's rebuttal testimony, the witness states that "DEF utilizes its portfolio of transportation contracts to obtain operational flexibility cost-savings, efficiencies, and other contractual benefits for DEF's customers to ensure a reliable, diverse and competitively priced fuel supply." Please complete the table below summarizing DEF's existing and projected portfolio of transportation contracts.

	BCF/Day
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	

RESPONSE:

	BCF/Day
2010	0.629
2011	0.709
2012	0.687
2013	0.717
2014	0.717
2015	0.717
2016	0.717
2017	0.929
2018	1.017
2019	1.017
2020	1.017

Note 1 – For purposes of preparing this table, these are annualized numbers. For example, the agreement with Sabal has an in service date of October 1, 2017.

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90. On page 22 of Witness Patton's rebuttal testimony, the witness states that "Calpine ignores the physical and contractual limitations on DEF transferring the gas under these system firm gas transportation arrangements to the Calpine Osprey plant." Please describe in detail the physical and contractual limitations mentioned in the quoted statement.

<u>**RESPONSE**</u>:

DEF's existing firm gas transportation contracts provide service to the proposed Suwannee CTs. There are physical limitations because the natural gas is supplied to Calpine's Osprey Plant via the Gulfstream Natural Gas Transmission Company, LLC ("Gulfstream") pipeline while the proposed Suwannee CTs are served by existing firm transportation agreements on the Florida Gas Transmission ("FGT") pipeline. DEF's existing FGT contracts cannot be utilized to physically deliver gas to Calpine's Osprey Plant on a separate gas pipeline. There are also contractual limitations based on the negotiated, specific firm gas receipt and delivery points in DEF's existing FGT contracts which correspond to DEF's existing and planned plants like the Suwannee Simple Cycle Project. DEF cannot realistically or even theoretically release firm gas transportation capacity to a third party like Calpine when this firm gas transportation capacity was specifically negotiated and contractually established based on DEF's specific receipt and delivery points for a defined contract term.

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 19th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jeffrey Patton, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory numbers 87 through 90 from STAFF'S FIFTH INTERROGATORIES NOS. 87-90 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 19th day of August, 2014.

BETH JENKINS HORSLEY
NOTARY
MY COMMISSION EXPIRES 8/25/2016
PUBLIC
GASTON COUNTY, NC

Jeffrey Patton

Beth Jenkins Horsley
Notary Public
State of North Carolina, at Large

My Commission Expires: 08-25-2016

106

DEF's responses to Staff's Sixth Set of Interrogatories, Nos. 91-93

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 106
PARTY: STAFF
DESCRIPTION: DEF's response to Staff's Sixth Set of Interrogatories, Nos. 91-93.
[Bates Nos. 00258-00264]

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 20, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO
STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 91-93)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Sixth Set of Interrogatories (Nos. 91-93) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Sixth Set of Interrogatories Nos. 91-93, served on August 18, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

Interrogatories for Witness Benjamin Bosch:

91. Did any party make an offer for the acquisition of a generation asset that would have both 1) passed a FERC market screen without requiring mitigation, AND 2) offer an equal or superior net present value option for Duke's customers? If so, please identify the party and describe the proposal.

RESPONSE:

No.

Interrogatories for Witness Julie Solomon:

92. On pages 7-8 of your rebuttal testimony, you note that if a Purchase Power Agreement (PPA) is solely entered into to avoid the market power screen, that FERC may treat the acquisition differently than it would a "vanilla" PPA. Are you aware of any examples of FERC affording different treatment to a similar case? If so, please identify any such examples.

RESPONSE:

Ms. Solomon is not aware of any instances in which the situation exists as it would here, namely where it would be made apparent that the sole reason for entering into the PPA followed by an acquisition is to facilitate approval under section 203 and, indeed, that, in one case, the PPA would be terminated if the acquisition were not approved.

93. On page 11 of your rebuttal testimony, you note that NRG Witness John Morris notes a "status quo" scenario that is different from the present situation.

a. Are you aware of FERC executing a market power analysis based on a "Status quo" that was markedly different than the present situation at the time of filing, e.g., with the assumption that a generation asset would relocate? If so, please identify any such instances.

b. Are you aware of FERC rejecting a petition that it do a market power analysis on a scenario differ from original filing? Please identify any examples you are aware of.

<u>RESPONSE</u>:

a. **Ms. Solomon is not aware of any instances in which FERC assumed that the purchaser would buy or build something pre-transaction that was not, in fact, yet being bought or built. Nor is she aware of any instances in which FERC has assumed that in the absence of being purchased, a plant would be shut down or moved out of the market.**

b. **Ms. Solomon is aware of instances in which FERC has asked applicants to revise their analysis based on changed assumptions. Ms. Solomon has not conducted any systematic research on that topic, but a review of section 203 matters where applicants have made supplemental filings would identify any changed assumptions. Examples that come to mind where FERC issued deficiency letters or requested additional analyses are the Duke Energy-Progress Energy merger, the MidAmerican Energy-NV Energy merger, and the Dynegy-Ameren transaction.**

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 20th day of August, 2014, 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 number 91 from STAFF'S SIXTH INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 91-93) in Docket No(s). 140111-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 August, 2014.

Benjamin M.H. Borsch
Benjamin M.H. Borsch

Sandra L Brice
Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 21st day of August, 2014, 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 number 91 from STAFF'S SIXTH INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 91-93) in Docket No(s). 140111-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 21st day of Aug, 2014.

Benjamin M.H. Borsch

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

AFFIDAVIT

STATE OF MASSACHUSETTS)

COUNTY OF Barnstable)

I hereby certify that on this 20th day of August, 2014, before me, an officer duly authorized in Massachusetts to take acknowledgments, personally appeared Julie Solomon, who is personally known to me or has provided identification, and has acknowledged before me that she provided the answers to interrogatory number(s) 92 and 93 from FLORIDA PUBLIC SERVICE COMMISSION STAFF'S SIXTH SET OF INTERROGATORIES NOS. 91-93 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal as of this 20th day of August, 2014.

Julie R Solomon

Julie Solomon

EUGENE J. DZIEDZINA, JR
Notary Public
Massachusetts
Commission Expires Dec 25, 2020

Eugene J. Dziedzina Jr

Notary Public

My Commission Expires:
12/25/2020

107

DEF's responses to Calpine's First Set of Interrogatories, Nos. 4, 5 (supplemental), 8

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 107
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's First Set of Interrogatories, Nos. 4, 5 (supplemental), 8. See also fi...

RECEIVED
JUN 17 2014
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

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: June 16, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-9)

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-9) as follows:

GENERAL OBJECTIONS

DEF incorporates and restates its General Objections to Calpine's First Set of Interrogatories (Nos. 1-9), served on June 4, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

4. Please identify any assumptions used by Duke in analyzing proposals in response to the RFP regarding future changes to state and federal energy and environmental policy regarding, e.g., emission standards for carbon dioxide, sulfur dioxide, nitrogen oxides, particulates, mercury/heavy metals; control requirements related to water use and impacts; controls on liquid or solid waste; nuclear safety upgrades; and/or changes to energy efficiency and/or renewable energy standards.

RESPONSE:

DEF's assumptions generally include forecasted compliance costs for certain specific EPA regulatory programs that are either in the development stage or can reasonably expected to be forthcoming in the near future. DEF makes no attempt to speculatively forecast areas of regulation not yet under serious consideration within the applicable regulatory agencies.

To this end, DEF assumes that EPA will promulgate additional rules regarding cooling water intake (316(b)), CO_2 emissions, renewable energy standards, and carbon combustion residuals. Air emissions of the six criteria pollutants are considered be governed by the CAIR and Title IV programs as well as the current and proposed NAAQS standards.

- **DEF's assumptions regarding 316(b) capital costs can be found in the response to question 5.d.vii below. These assumptions were generally not material to the analysis since the Citrus project plans to install closed loop cooling and is designed to be in compliance with the current standards for new plants under 316(b). None of the competing bids were coastal facilities subject to 316(b).**
- **DEF reasonably anticipates that CO_2 emissions will have a future regulatory cost. DEF has included a price for carbon emissions which may be interpreted as an allowance price, an equivalent carbon tax, or a proxy for other changes which may be required. The values used are shown in the spreadsheet attached.**
- **DEF assumes a future federal renewable portfolio standard requiring that DEF obtain 0.5% of energy from renewable sources in 2020 increasing 0.5% per year to 2.5% in 2024. This assumption was not generally material to the analysis since DEF currently obtains approximately 3% of its energy from renewable source and expects to continue to do so through renewal and replacement of existing contracts.**
- **DEF assumes that carbon combustion residual rules will require a phasing out of wet ash handling and will continue to maintain a provision for beneficial reuse of coal ash. DEF did not include a specific cost for compliance with this rule since DEF currently sells all of its ash and gypsum for beneficial reuse and anticipates being able to do so in the future.**
- **DEF has assumed allowance prices for NOx and SO_2 to achieve compliance with CAIR. At the time this analysis was performed, the Supreme Court ruling reinstating CSAPR had not been made. The proposed Suwannee Simple Cycle and Hines Chillers Power Uprate projects are anticipated to comply with the current and proposed NAAQS. DEF also assumed that there would be no NAAQS related impacts on any of the bidding facilities. DEF assumed emissions rates for NOx and SO_2 from bidding facilities as specified in Schedule 6 of each bid. The impacts of these costs are shown in responses to Question 7.**

None of the above assumptions with the exception of the CO_2 price assumption was considered to be material to the analysis. To examine the impact of the CO_2 price assumption on the results, DEF performed a no-carbon price sensitivity.

See documents Docket_140111-EI_Q4.xlsx produced in Bates range 14LGBRA-CALPINE1-4-DOC1.

5. Please identify all common inputs Duke used in running the Strategist model, or in running any other model used, for the evaluation of proposals in response to the RFP. Please provide these inputs in a consistent format for each scenario and sensitivity studies. Such inputs should be identified for all years of the modeling period, and include, but not be limited to, the following:

a. Area studies;

b. Forecast of fuel prices for all fuel types included in the analysis;

c. Forecast of peak load and energy over the forecast horizon, including assumptions regarding imports and exports of power from the electrical region studied in the model(s);

d. List of generating units and demand response resources assumed to be available and operating in any year of the modeling period, including the following items for each individual unit:

i. Nameplate and seasonal capacity;

ii. Fuel and technology type;

iii. Actual amount capacity factors for the past three years;

iv. Year entered into service;

v. Heat rate assumed for modeling purposes;

vi. Major upgrades or modifications in the past 5 years;

vii. Expected future capital investment or operational change including, for example, steps to meet any current or future federal or state environmental control requirement (air, water, liquid/solid waste);

viii. Planned or expected year of retirement;

e. Forecast of energy and/or capacity purchases and sales within or into/out of the area modeled;

f. Expectations or model assumptions related to the addition of new resources and retirement of existing resources;

g. Forecast of changes in transmission or other power system infrastructure;

h. Financial assumptions (e.g., tax rate(s), discount rate(s), cost of debt/equity, etc.).

RESPONSE:

Except as noted below, information requested in this question and its subparts is provided in Excel file Docket_140111-EI_Q5.xlsx in Bates range 14LGBRA-CALPINE1-5-DOC1. This document is confidential and subject to DEF's Second Notice of Intent filed contemporaneously with service of this response.

a. Area studies;

RESPONSE:

The area studied was DEF's control area. All resources were dispatched to meet DEF's native load and committed wholesale contracts. All resources in addition to the bid resources were DEF owned or contracted resources with transmission within the DEF system or delivered to the DEF border.

d. List of generating units and demand response resources assumed to be available and operating in any year of the modeling period, including the following items for each individual unit:

iii. Actual amount capacity factors for the past three years;

RESPONSE:

DEF is working to provide this data. Data will be supplied when available.

vi. Major upgrades or modifications in the past 5 years;

RESPONSE:

Project	Year
Crystal River 4/5 Scrubber/SCR Projects	In Service 2009
Anclote Gas Conversion	In Service 2013
Crystal River 1/2 ESP Upgrades/ Fuel Change	In Service 2015

viii. Planned or expected year of retirement;

RESPONSE:

In modeling future projections, DEF projects end of life only for units being considered in the study. It is recognized that other existing units will reach the end of lives during the study period. To make the modeling feasible, however, these future resource decisions are removed from the study by assuming that the existing units which are common to all cases continue operation throughout the study period.

e. Forecast of energy and/or capacity purchases and sales within or into/out of the area modeled;

RESPONSE:

Information regarding projected sales is provided in Excel file Docket_140111-EI_Q5.xlsx. Purchase capacities are shown in the response to Question 6 below. Energy purchased is projected for each case as part of the run output shown in the response to Question 7 below.

g. Forecast of changes in transmission or other power system infrastructure;

RESPONSE:

The only changes modeled in the forward looking evaluations are those identified as necessary to the addition or retirement of units identified in the study. Planned upgrades to the system driven by other factors, e.g. NERC Standards, are considered to be constant across the scenarios and are not included in the cases for modeling since, being common to all cases, they would not affect the differential result.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination	)	
of Cost Effective Generation Alternative	)	DOCKET NO. 140111-EI
to Meet Need Prior to 2018 for Duke	)	Submitted for filing: July 17, 2014
Energy Florida, Inc.	)	
______________________________	)	

DUKE ENERGY FLORIDA, INC.'S SUPPLEMENTAL RESPONSE TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NO. 5.D.III)

Duke Energy Florida, Inc. ("DEF") provides this supplemental response to Calpine Construction Finance Company, L.P.'s First Set of Interrogatories to Duke Energy Florida, Inc. (No. 5d.iii) as follows:

GENERAL OBJECTIONS

DEF incorporates and restates its General Objections to Calpine's First Set of Interrogatories (Nos. 1-9), served on June 4, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

5. Please identify all common inputs Duke used in running the Strategist model, or in running any other model used, for the evaluation of proposals in response to the RFP. Please provide these inputs in a consistent format for each scenario and sensitivity studies. Such inputs should be identified for all years of the modeling period, and include, but not be limited to, the following:

    iii. Actual amount capacity factors for the past three years.

RESPONSE:

Please see document attached bearing Bates number 14LGBRA-CALPINE1-SUPP5-000001.

RECEIVED
JUL 18 2014
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OFFICE OF THE GENERAL COUNSEL

8. In modeling proposals in response to the RFP (if at all) does Duke evaluate or adjust evaluation to address timing differences for proposed online or contract dates.

RESPONSE:

In this evaluation, PPA responses were requested to begin in June 2016 and were evaluated on that basis. Acquisitions were assumed to be available in June 2014. In all cases, resource plans were optimized around the specific resources proposed (See the response to Question 5.I). The results of the modeling both in resource optimization and in detailed production costs reflected any costs or benefits resulting from timing differences.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this ________ day of June, 2014, 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) 1 through 9 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1-9) in Docket No(s). 140111-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 13th day of June, 2014.

Benjamin M.H. Borsch

Benjamin M.H. Borsch

Sandra L Brice

Notary Public
State of Florida, at Large

My Commission Expires:

____

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

108

DEF's responses to Calpine's Second Set of Interrogatories, No. 10

<u>See also</u>: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 108
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's Second Set of Interrogatories, No. 10. See also file contained on Staf...

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: June 24, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S SECOND SET OF INTERROGATORIES (NOS. 10-11)

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s Second Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 10-11) as follows:

GENERAL OBJECTIONS

DEF incorporates and restates its General Objections to Calpine's Second Set of Interrogatories Nos. (10-11), served on June 16, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

10. Please provide the additional inputs not included in the RFP related to each Duke-proposed resource or upgrade (Citrus CC, Suwanee CT, or Hines Chiller) or generic units that Duke used in running the Strategist model, or in running any other model used, for the evaluation of proposals in response to the RFP. Please provide these inputs in a consistent format for each scenario and sensitivity studied:

    a. Unit-specific assumed fuel delivery or service charges (including firm gas transportation costs);

    b. Emissions intensity (lbs/mmBtu) for Sulfer Dioxide, Nitrogen Oxide, Carbon Dioxide, Particulate Matter, Carbon Monoxide, Mercury, and any other regulated compounds;

    c. Any other relevant variable cost (fired hour charge, dispatch payment, etc.);

    d. Financial assumptions, including depreciation schedule and deprecation rates.

REDACTED

RESPONSE:

a. In the case of the Suwannee CT project and the Hines Chiller projects, DEF has concluded that no additional fixed gas transportation capacity is required for the operation of these units. Values for the Citrus combined Cycle (NPGU) and the DEF generic units are given in the table below.

Fixed Reservation Charges

Unit	Source	Volume Dt/day	2018 Rate	Transco MBS Demand Adder	Lateral Charges	2018
NPGU	Sabal Trail	300,000	[redacted]	$0.0000	included in [redacted]	[redacted]
DEF Generic CC	FGT Ph 8	97,553	1.25	$0.2875	0.05	$1.588
DEF Generic 2018 CT	FGT Ph 8	23,167	1.25	$0.2875	0.05	$1.588
DEF Generic 2018 CC	FGT Ph 8	97,553	1.25	$0.2875	0.05	$1.588
DEF Generic CC after 2018	Sabal Trail	48,810	[redacted]	$0.0000	included in [redacted]	[redacted] 1)

(1) FT price for Generic CC after 2018 escalates 2.5%/yr to the first year in service.

b. Emissions rates (lb/mmBtu) are supplied in the attached Excel file. DEF does not model emissions for Carbon Monoxide, Particulate Matter, Mercury or HAPs in planning modeling and addresses these emissions on a project basis during project planning and permitting

c. All variable cost charges are incorporated into the VOM and Start charge rates supplied in DEF's Response to Calpine's Interrogatory # 6.

d. Base financial data is supplied in DEF's Response to Calpine's Interrogatory #7.h. All depreciation was done on a straight line basis.

In general, all CC units are depreciated over 35 years. All CT units are depreciated over 35 years. These values were used for the Suwannee CTs and Citrus Combined Cycle.

Each of the Hines Power Blocks (1 – 4) has its own depreciation schedule based on the in-service date as shown below. In the model, the depreciation of the Hines units was not a differential factor. DEF does not assume the retirement of units in its portfolio in new generation analyses unless the retirements are imminent (next 10 years) or specifically subject to study. The chillers were assigned a life of 29 years to extend their depreciation to the end of the study.

Power Block	In Service Year	Depreciation End
1	1999	2034
2	2003	2038
3	2005	2040
4	2007	2042

35122444.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 24th day of June, 2014, 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) 10 and 11 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 10-11) in Docket No. 140111-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 24th day of June, 2014.

Benjamin M.H. Borsch

Sandra L Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

109

DEF's responses to Calpine's Third Set of Interrogatories, Nos. 12, 15

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 109
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's Third Set of Interrogatories, Nos. 12, 15.
[Bates Nos. 00280-00284]

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 Served: July 2, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S THIRD SET OF INTERROGATORIES (NOS. 12-15) TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s Third Set of Interrogatories (Nos. 12-15) to Duke Energy Florida, Inc. as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Calpine Construction Finance Company, L.P.'s Third Set of Interrogatories (Nos. 12-15), served on June 26, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

12. Please provide the following information regarding assumptions about generating unit retirements:
    a. Refer to BMHB-4 in Docket 140111-EI (short term need) and BMHB-3 in Docket 140110-EI (long term need). Please provide a detailed breakout of the summer installed capacity excluding the Duke self-build options proposed in Docket 140110-EI and Docket 140111-EI. In particular, please confirm exactly which generating units noted in Schedule 1 of the Duke Energy Florida Ten-Year Site Plan were assumed to be retired, and provide the assumed retirement dates for each such unit (month and year).

RESPONSE:

	DEF's Fleet Baseline	Cumultive Fleet Additions	Cumulative Fleet Retirements	DEF's Net Additions	PPA-Cogens-Renewables Baseline	PPA-Cogens-Renewables Cumulative Additions	PPA-Cogens-Renewables Cumulative Retirements	PPA-Cogens-Renewables Net Additions	Total Net Additions	Total Capacity	Peak	Peak with Reserve Margin	Reserve Margin	MW Shortage
2014	8,935	103	(23)	80	2,100	95.80	(187.00)	(91)	(11)	11,024	8,812	10,575	25.1%	449
2015	8,935	123	(76)	47	2,100	95.80	(187.00)	(91)	(44)	10,991	9,042	10,850	21.6%	141
2016	8,935	123	(413)	(290)	2,100	550.80	(600.00)	(49)	(339)	10,696	9,149	10,979	16.9%	(283)
2017	8,935	123	(413)	(290)	2,100	550.80	(600.00)	(49)	(339)	10,696	9,307	11,168	14.9%	(472)
2018	8,935	123	(1,153)	(1,030)	2,100	600.80	(600.00)	1	(1,029)	10,006	9,439	11,327	6.0%	(1,321)
2019	8,935	123	(1,153)	(1,030)	2,100	600.80	(650.00)	(49)	(1,079)	9,956	9,813	11,775	1.5%	(1,820)
2020	8,935	123	(1,258)	(1,135)	2,100	600.80	(650.00)	(49)	(1,184)	9,851	9,935	11,922	-0.8%	(2,071)
2021	8,935	123	(1,258)	(1,135)	2,100	600.80	(650.00)	(49)	(1,184)	9,851	9,952	11,942	-1.0%	(2,092)
2022	8,935	123	(1,258)	(1,135)	2,100	600.80	(1,075.00)	(474)	(1,609)	9,426	10,067	12,081	-6.4%	(2,655)
2023	8,935	123	(1,258)	(1,135)	2,100	600.80	(1,075.00)	(474)	(1,609)	9,426	10,173	12,207	-7.3%	(2,781)
2024	8,935	123	(1,258)	(1,135)	2,100	600.80	(1,665.42)	(1,065)	(2,200)	8,835	10,277	12,332	-14.0%	(3,497)
2025	8,935	123	(1,258)	(1,135)	2,100	600.80	(1,780.42)	(1,180)	(2,315)	8,720	10,374	12,449	-15.9%	(3,729)
2026	8,935	123	(1,258)	(1,135)	2,100	600.80	(1,884.42)	(1,284)	(2,419)	8,616	10,464	12,557	-17.7%	(3,941)
2027	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,555	12,667	-24.4%	(4,689)
2028	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,642	12,770	-25.0%	(4,792)
2029	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,728	12,873	-25.6%	(4,896)
2030	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,808	12,970	-26.2%	(4,992)
2031	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,884	13,061	-26.7%	(5,083)
2032	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	10,959	13,151	-27.2%	(5,173)
2033	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,523.24)	(1,922)	(3,057)	7,977	11,031	13,237	-27.7%	(5,260)
2034	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,102	13,323	-28.7%	(5,405)
2035	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,171	13,406	-29.1%	(5,488)
2036	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,237	13,484	-29.5%	(5,567)
2037	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,312	13,574	-30.0%	(5,657)
2038	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,389	13,667	-30.5%	(5,749)
2039	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,462	13,755	-30.9%	(5,837)
2040	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,536	13,844	-31.4%	(5,926)
2041	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,609	13,931	-31.9%	(6,014)
2042	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,682	14,019	-32.2%	(6,101)
2043	8,935	123	(1,258)	(1,135)	2,100	600.80	(2,583.24)	(1,982)	(3,117)	7,917	11,764	14,117	-32.7%	(6,200)

Summer Values

35349947.1

15. Refer to the 2014 Ten-Year Site Plan, sections 2-16 and 2-17. Duke Energy Florida notes that "a risk to this projection lies in the price of energy." Did Duke consider changes to its load forecast consistent with the high gas price Strategist sensitivity referenced in the Direct Testimony of Benjamin M.H. Borsch in the Petition for Determination of Need for Citrus County Combined Cycle Power Plant, at p. 78?

RESPONSE:

No. A separate load forecast was not prepared for the high gas price sensitivity. The Company uses a robust load forecasting methodology which examines forecasts of economic growth and historic weather and customer usage. Given the detailed analysis used to develop the load forecast, the Company determined that sensitivities would not yield markedly different results.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of July, 2014, 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) 12 through 15 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 12-15) in Docket No. 140111-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Sandra L. Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

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110

DEF's responses to Calpine's Fourth Set of Interrogatories, No. 18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 110
PARTY: STAFF
DESCRIPTION: DEF's responses to Calpine's Fourth Set of Interrogatories, No. 18. [Bates Nos. 00285-00288]

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 Served: July 10, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES (NOS. 16-18) TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") responds to Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 16-18) to Duke Energy Florida, Inc. as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Calpine Construction Finance Company, L.P.'s Fourth Set of Interrogatories (Nos. 16-18), served on June 26, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

18. Refer to the Direct Testimony of Mark E. Landseidel, Docket 140111-EI (page 12). To the extent not addressed in the responses to Interrogatories No. 3 and No. 4 (served on May 30, 2014), please provide an electronic copy and numeric breakdown for the fixed and variable O&M cost increases at the Hines Energy Complex associated with the Hines Chillers Power Uprate.

RESPONSE:

The annual fixed O&M increase at the Hines Energy Complex associated with the Hines Chiller Power Uprate was estimated to be $70,000 per unit, which corresponds with $280,000 for the site. Variable O&M rates for the Hines units remained the same in the planning analysis, so any cost increases would be based on projected increases in plant generation. These detailed results were included in the responses provided in this docket to Calpine's 1st Interrogatories Number 7. There is no further numeric breakdown of these cost figures.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 2nd day of July, 2014, 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) 16 and 17 from CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 16-18) in Docket No. 140111-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 2nd day of July, 2014.

Benjamin M.H. Borsch

Sandra L. Brice

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA L. BRICE
Commission # FF 071476
Expires February 10, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

35427837.1

111

DEF's responses to NRG's First Set of Interrogatories, Nos. 2-4, 6, 14, 18, 21, 23-25, 27, 35-36, 38, 63, 69-70, 76, 84, 100

See also: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 111
PARTY: STAFF
DESCRIPTION: DEF's responses to NRG's First Set of Interrogatories, Nos. 2-4, 6, 14, 18, 21, 23-25, 27, 35-36, 38...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	Docket No. 140111-EI Served: July 7, 2014

REDACTED

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO NRG FLORIDA LP'S FIRST INTERROGATORIES NOS. 1-108 TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") responds to NRG Florida LP's First Interrogatories Nos. 1-108 to Duke Energy Florida, Inc. as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to NRG's First Interrogatories Nos. 1-108, served on June 23, 2014, as if those objections were fully set forth herein.

INTERROGATORIES

THE FOLLOWING QUESTIONS RELATE TO DUKE'S PETITION:

1. Please provide the detailed calculations supporting the size and the timing of the Suwannee and Hines Energy Center additions.

RESPONSE:

DEF will provide a response in a supplemental production.

2. Please provide the computation of the emission reductions arising from the Suwannee Peakers and the Hines Chiller Power Uprate Project ("Hines Chillers") for each year of the evaluation period.

<u>RESPONSE</u>:

Please see Tab 2 of Excel Workbook "Docket 140111 NRG First.xlsx" attached in Bates range 14LGBRA-NRGROG1-2-000001 through 14LGBRA-NRGROG1-2-000012. See also the response to Interrogatory Number 13 below.

3. Please provide the expected capacity factor and operating hours of the existing Hines CCGT prior to and after the installation of the Hines Chillers for each year of the evaluation period.

RESPONSE:

Please see Tab 3 of Excel Workbook "Docket 140111 NRG First.xlsx" attached in Bates range 14LGBRA-NRGROG1-2-000001 through 14LGBRA-NRGROG1-2-000012.

4. Please provide the gross and net heat rate and output of Hines Energy Center with and without the Chillers for each year of the evaluation period.

RESPONSE:

Please see Tab 4 of Excel Workbook "Docket 140111 NRG First.xlsx" attached in Bates range 14LGBRA-NRGROG1-2-000001 through 14LGBRA-NRGROG1-2-000012. The model provides annual net heat rate values which are provided in the attachment.

6. Re: paragraph 10: Please provide the amount of fuel oil that will be stored on-site for Suwannee Peaker operation, the expected permitted annual hours of oil operation, whether the fuel oil will be exclusively used for the new Suwannee Peakers, and what upgrades will be made to on-site fuel oil storage, if any.

   RESPONSE:

   The current Suwannee Simple Cycle Project design and cost estimate includes provisions for a new 2.5M gallon oil storage tank to support the new units. The project team may consider an alternative to refurbish an existing 4.2M gallon oil tank if it is determined to be feasible, but that determination has not yet been finalized. DEF's permit application requests agency review and approval of 500 hours/yr/unit of operation of the new units on ultra-low sulfur diesel (ULSD) fuel oil.

14. Re: paragraph 11: Define the fast start capability of the Suwannee Peakers.

<u>**RESPONSE**</u>:

The project specifications call for the new Suwannee peaking units to be able to sync to the grid within 19 minutes.

18. Re: paragraph 16: Please provide the estimated fixed and variable costs for each year of the evaluation period of the Hines Chiller Uprate projects.

RESPONSE:

The annual estimated incremental fixed costs associated with the Hines 1-4 Chiller Uprate project is $0.28M in year 2017 escalated by 2.5% after 2017. The variable cost for the Hines Units ($/Mwh) did not change incrementally with the addition of the Inlet Chillers.

21. Please provide the expected capacity factors and operating hours of Duke's CCGT fleet by plant, and by unit with and without the Hines Energy Chillers.

<u>RESPONSE</u>:

Please see Tab 21 of Excel Workbook "Docket 140111 NRG First.xlsx" attached in Bates range 14LGBRA-NRGROG1-2-000001 through 14LGBRA-NRGROG1-2-000012.

23. Please describe the water source for the Hines Energy Chillers and all required regulatory approvals and timeline for the water withdrawal. Has Duke developed a contingency plan if these permits are not obtainable?

RESPONSE:

The water source for the Hines Energy Chillers will be the existing cooling pond or other alternative water supply sources (such as stormwater capture and storage, or recycled industrial wastewater) at the site. No additional groundwater is being requested to support the chiller project. Duke Energy has had preliminary discussions with the Southwest Florida Water Management District (SWFWMD) regarding the potential need to modify the Conditions of Certification associated with utilization of either the existing cooling pond or alternative water supplies as a makeup water source to the Chiller cooling towers. The District has agreed conceptually to the use of these sources, but they are considering if there is a need to independently quantify this use. If a modification is deemed necessary, it can be obtained within 6 months of filing, and in advance of the need to quantify the proposed water use.

24. Please provide the estimated increase in wastewater discharge with the addition of the Hines Chillers.

RESPONSE:

Based on the preliminary water balance the increase in waste water discharge will be approximately 700 gpm.

25. Please provide the incremental estimated annual fuel costs associated with the Hines Energy chillers.

RESPONSE:

Please see Tab 25 of Excel Workbook "Docket 140111 NRG First.xlsx" attached in Bates range 14LGBRA-NRGROG1-2-000001 through 14LGBRA-NRGROG1-2-000012.

27. Please provide a comparison of the emission rates of Crystal River 1 and 2 to the emission rates of the GE 7FA technology planned for Suwannee including NOx, SO2, CO2, HG, PM10, and PM2.5.

__RESPONSE__:

The emission rates used in DEF's planning models for each of the facilities requested are listed below. The planning models do not reflect particulate emissions (PM), so those values are not included.

Table: Emission Rates Used in Modeling (lb/mmbtu)

		NOx	CO2	SO2	Hg
Crystal River 1	**2013**	0.40	205.3	1.66	4.92E-06
	2016	0.36	205.3	0.96	3.61E-06
Crystal River 2	**2013**	0.43	205.3	1.66	4.92E-06
	2016	0.27	205.3	0.96	3.61E-06
New Suwannee CTs	**2013**	0.0106	117.1	0.0006	-

35. Please describe whether and to what extent the existing gas pipeline infrastructure is capable of supporting the simultaneous full dispatch of the existing combustion turbines and the proposed Suwannee Peakers on natural gas.

RESPONSE:

The existing pipeline infrastructure is capable of supporting the simultaneous full dispatch of the existing combustion turbines and the proposed Suwannee Peakers on natural gas. Suwannee is a served by a Florida Gas Transmission high pressure 20 inch lateral. The meter station for the station has a daily point capacity of approximately 235,000 MMBtu/day and an hourly capability of approximately 14,100 MMBtu/hour. The full load rate for the existing combustion turbines is approximately 1,500 MMBtuu/hr. The full load rate for the new combustion turbines is approximately 3,800 MMBtu/hr.

36. Does Duke currently have firm transportation for this quantity of gas to the facility?

<u>**RESPONSE**</u>:

Yes. Duke Energy has firm transportation to the facility of approximately 106,300 MMBtu/day for summer period (April through October) with 6 % hourly rights of approximately 6,378 MMBtu/hour, and approximately 107,600 MMBtu/day in the winter months (November through March) with 6% hourly rights of approximately 6,456 MMBtu/hour.

38. Please describe in detail the reason for the proposed retirement of the existing steam units at the site, indicating and explaining whether the existing steam units will be required in 2018 if the Suwannee Peakers are not constructed.

RESPONSE:

The existing steam units are being retired in 2016 (vs. their scheduled retirement date of 2018) for several reasons. DEF transmission analysis showed that retiring the steam units at the time of commercial operation of the peakers would avoid the need for significant transmission upgrades, reducing the transmission upgrade costs from approximately $70 million to the forecast $15.7 million. In addition, retirement of at least Suwannee Unit 3 is required in the air permitting analysis to allow for potentially needed operation on distillate oil in the event of gas supply interruptions.

63. Please provide the basis for "typical" firm gas transportation for a utility asset compared to a non-utility generator or exempt wholesale generator such as NRG.

RESPONSE:

DEF recognizes that within Peninsular Florida, there has historically been a general constraint on the availability of gas to the extent that gas transportation in the state has been fully subscribed. During peak operation periods, especially on the East Leg of FGT, firm subscribers have fully utilized the gas transportation resources limiting the amount of "non-firm" gas available during those periods. DEF plans its gas portfolio to provide sufficient firm gas transportation to provide for economically efficient dispatch of its units under peak normal weather conditions. In evaluating new combustion turbine generation DEF's generic assumption is these units operate off of the East Leg of FGT's system and require sufficient firm gas transportation to provide 12 hours of daily operation. At the time a specific project is sited, DEF evaluates that project in the context of the existing gas portfolio at the time, the projected location and the availability of DEF committed firm gas and non-firm gas deliverable to that specific location in order to determine an appropriate amount of transportation required to support the project.

69. Please provide the staffing level attributed to the operation of the Suwannee Peakers and the Hines chillers including any incremental permanent jobs created at either location.

RESPONSE:

For staffing related to the Suwannee Simple Cycle Project, the facility expects to support either 14 or 15 full time equivalent (FTE) positions after the existing steam units retire and the new simple cycle units are operational. The current facility supports 35.5 FTE positions, so there will be a net reduction. For staffing levels related to the Hines Uprate Project, there are currently no proposed new FTE positions at the facility.

70. Mr. Borsch states that Duke proposes to retire the Suwannee steam generation plants 2-years early to reduce the cost of the transmission upgrades needed for installation of the proposed Peakers. Please provide the cost of the transmission upgrades that would be required if the steam generation plants are not retired.

RESPONSE:

The costs of the transmission upgrades that would be required if the steam generation plants are not retired and the proposed Peakers are installed are estimated to be $77.2 Million.

76. Assuming Duke purchased Osceola from NRG, is it Mr. Borsch's opinion that Duke would not be able to negotiate with its current gas supplier firm transportation service for Osceola on the same terms as Duke currently has in place for Suwannee and Hines? Please provide a clear and fully developed response explaining why a contract with comparable firm transportation rights including transportation rates Duke's has with its current gas transportation provider would not be available for Osceola.

<u>RESPONSE</u>:

Please see DEF's responses to Interrogatories Numbers 62, 63, 73, 74, and 75. Based on those responses, DEF has assumed that, in the event of an acquisition of the facility, it would negotiate additional firm gas supply for the facility. The assumption is that the supply would be at current FTS – 3 rates or at a higher rate including any necessary upgrades on the pipeline. As noted in the response to Interrogatory number 75 above, DEF used its generic price assumption of $1.50/Dt.

DEF's current portfolio of firm gas supply contracts which serve Suwannee and Hines as well as its other gas fired facilities are composed of a large number of contracts negotiated in different years as DEF's gas needs have evolved. Each contract may have several delivery points depending on the needs at the time negotiated. DEF does not believe, based on the location of Acquisition 1 relative to DEF's current delivery points that it will be able to add the Acquisition 1 site to its current group of primary delivery points for firm gas from its current portfolio, but would need to add additional transportation as discussed above in DEF's responses to Interrogatories Numbers 62, 63, 73, 74, and 75.

84. Page 40, li 22, Mr. Borsch states that the 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. Does this mean that the PV revenue requirement study presented on Exhibit BMHB-8, Acquisition 1 compared Osceola to both Hines and Suwannee? If so please provide a detailed explanation and workpapers that demonstrates that including Hines in the comparison study made the project more favorable from a CPVRR perspective.

RESPONSE:

The Hines Chillers are included in both the Self Build case that includes the Suwannee CTs and the case with the Osceola Acquisition.

Two plans were compared one with Hines 1-4 Chillers and one without Hines Chillers and the one with all 4 Chillers showed a $52M CPVRR savings.

100. Please provide the labor and labor related operating costs for the employees required for plant operation including dedicated and shared headcount for the Suwannee Simple Cycle Project.

RESPONSE:

The typical annual labor and labor related operating costs for the Suwannee facility are projected to be $1.2M/yr with nominal escalation for future years. This projected cost includes the dedicated and shared positions attributed to the facility.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 7th day of July, 2014, 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 answers to interrogatory number(s) 5, 6, 8, 10, 11, 14, 18, 19, 23, 24, 30, 33, 34, 41, 60, 69, 78, 79, 80, 98, 99, 100 and 103 from NRG FLORIDA, LP'S FIRST INTERROGATORIES NOS. 1 – 108 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 7th day of July, 2014.

Mark E. Landseidel

Notary Public
State of ~~Florida,~~ North Carolina at Large

My Commission Expires:
October 20, 2018

35510688.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 9th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ed Scott, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 9, 37, 39, 70, 72, 106, 107, 108 from NRG FLORIDA, LP'S FIRST INTERROGATORIES NOS. 1 – 108 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 9th day of July, 2014.

Ed Scott

Sandra Cope

Notary Public
State of Florida, at Large

My Commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2016
Commission # FF 070867

35511353.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 25th day of July, 2014, 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) 1 through 4, 7, 12, 13, 15 through 17, 19 through 22, 25 through 32, 38, 40, 42 through 53, 55 through 68, 71, 73 through 77, 81 through 98, 101, 102, 104 and 105 from NRG FLORIDA, LP'S FIRST INTERROGATORIES NOS. 1 – 108 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 25th day of July, 2014.

Benjamin M.H. Borsch

Sandra C

Notary Public
State of Florida, at Large

My Commission Expires:
6/8/18

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 079967

35510502.1

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 25th day of July, 2014, 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) 1, 43, 47, 55, 61, 71 and 88 from NRG FLORIDA, LP'S FIRST INTERROGATORIES NOS. 1-108 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 25th day of July, 2014.

Benjamin M.H. Borsch

Sandra Cope
Notary Public
State of Florida, at Large

My Commission Expires:
8/8/18

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

35510502.3

AFFIDAVIT

WASHINGTON, D.C.)

I hereby certify that on this _________ day of July, 2014, before me, an officer duly authorized in Washington, D.C. aforesaid to take acknowledgments, personally appeared Julie Solomon, who is personally known to me or has provided identification, and has acknowledged before me that she provided the answers to interrogatory number(s) 54 from NRG FLORIDA LP's FIRST SET OF INTERROGATORIES NOS. 1-108 TO DUKE ENERGY FLORIDA, INC. in Docket No(s). 140111-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal as of this 7th day of July, 2014.

Julie R Solomon
Julie R. Solomon

Notary Public

My Commission Expires:

ZACHARY FAGIANO
Notary Public
Massachusetts
Commission Expires Dec 18, 2020

35402490.1

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBERG)

I hereby certify that on this 21st day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jeffrey Patton, who is personally known to me. and he acknowledged before me that he provided the answers to interrogatory number(s) 6, 35, 36 from NRG FLORIDA, LP'S FIRST INTERROGATORIES NOS. 1 - 108 TO DUKE ENERGY FLORIDA, INC. in Docket No. 140111-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 21st day of August, 2014.

RITA G KALE
NOTARY PUBLIC
CATAWBA CO., NORTH CAROLINA

Jeffrey Patton

Rita G Kale
Notary Public
State of North Carolina, at Large

My Commission Expires:
6/17/2017

35511127.1

112

Calpine's responses to Staff's First Set of Interrogatories, Nos. 1-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 112
PARTY: STAFF
DESCRIPTION: Calpine's responses to Staff's First Set of Interrogatories, Nos. 1-4. [Bates Nos. 00317-00326]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI SERVED: AUGUST 4, 2014

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P. (NOS. 1-4)

Calpine Construction Finance Company, L.P. ("Calpine") hereby files its responses to Staff's First Set of Interrogatories (Nos. 1-4), which were propounded on Calpine on July 23, 2014. All of Calpine's responses are subject to Calpine's general objections to Staff's interrogatories, which Calpine served on July 25, 2014, and Calpine does not waive any such objections.

RESPONSES TO SPECIFIC INTERROGATORIES

1. On page 13 the witness states that the actual cost of the direct connection facilities will, most likely, be less than $150 million. Please state the estimated cost of the direct connection facilities. Furthermore, please state the factual basis for your estimate.

Calpine's Response:

Based on Mr. Simpson's knowledge of and experience with transmission line construction in Florida and elsewhere in the United States, the range of costs per mile for new 230 kV transmission line construction in Florida is between $1.5 million and $2.0 million per mile. Accordingly, in Mr. Simpson's opinion, a very reasonable value to use for the estimated cost of the direct connection transmission lines is $1.7 million per mile. Using this value and the estimated lengths provided by Duke witness Ed Scott, the estimated cost of the 30 mile Kathleen to Recker 230 kV line is $51 million and the estimated cost of the 20 mile Recker to Haines City East 230 kV line is $34 million. Adding the estimated costs for the substation work at Recker ($10 million), Kathleen ($10 million), and Haines City East ($5 million), a more accurate estimate of the direct connection facilities would be $110 million. This cost per mile for new 230 kV transmission line construction is based on the actual costs of similar facilities in other parts of the United States with a recognition of regional differences and specific requirements for construction in Florida. (Simpson)

2. On page 15 the witness states that it is his opinion that the total cost of all required transmission upgrades to the FRCC grid through the planning horizon is no more than $150 million. Is the $150 million described on page 15 inclusive of the $150 million discussed on page 13 of the witness's testimony or are the two values additive?

Calpine's Response:

The $150 million described on page 15 is inclusive of the $150 million discussed on page 13. The values are not additive. As stated in Mr. Simpson's response to Interrogatory No. 1 above, Mr. Simpson believes that the best estimate of the actual costs for the subject transmission upgrades is $110 million, and this value is not additive. (Simpson)

3. On page 15 the witness states that DEF has not placed a monetary value on the transmission benefits described on pages 14 and 15 of the witness's testimony. What does Calpine believe would be a reasonable monetary value for the described transmission benefits? Please provide the factual basis for your answer. (i.e., how was value determined).

Calpine's Response:

The addition of the direct connection facilities to integrate the Osprey Facility into Duke's system will create a southern tie between Duke's two major load centers, the Florida Suncoast and Central Florida areas. This direct connection project, connecting the Haines City East substation to the Recker Substation, and the Recker Substation to the Kathleen substation, would probably defer the need to construct another tie between these load centers for at least 10 years beyond the date when such other facilities might otherwise be needed. While Duke presently does not indicate a specific project to connect these major load centers, load growth and/or the addition of generation could drive the need to add such transmission capabilities at any time. Assuming that an additional tie might be added in 2019, at a cost of $100 million, the economic value of the Haines City East-Recker-Kathleen direct connection lines would be the value of deferring the new tie, which is estimated to be approximately $40 million in present value benefits in 2014 dollars, using Duke's discount rate of 6.46 percent. If the line were needed earlier, the present value of these benefits would be greater, and if later, the present value of these benefits would be less. (Simpson)

4. Has Calpine sought a statement from the FERC regarding the impact on market power if DEF purchased the Osprey Energy Center?

a. If yes, please provide FERC's response.

b. If no, why not?

Calpine's Response:

Calpine has not sought a statement from the FERC regarding FERC's assessment of the impact on market power if DEF were to acquire the Osprey Energy Center. It is premature to seek a market power determination from FERC at this time because FERC will not entertain applications for market power determinations without the definitive transaction documents. (Hunger)

Respectfully submitted this 4th day of August, 2014.

Robert Scheffel Wright

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Attorneys for Calpine Construction Finance Company, L.P.

AFFIDAVIT

DISTRICT OF COLUMBIA)
)
)

I hereby certify that on this 5th day of August, 2014, before me, an officer duly authorized in the District of Columbia to take acknowledgements, personally appeared David Hunger, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory No. 4 in STAFF'S FIRST SET OF INTERROGATORIES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P. in Docket No. 140110-EI, and that the responses are true and corrected 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 5th day of August, 2014.

CORLIS C. CARTER NOTARY PUBLIC EXP. 6-14-2019 DISTRICT OF COLUMBIA

David Hunger

Corlis C. Carter

Notary Public
District of Columbia

My Commission Expires:

CORLIS C. CARTER
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 14, 2019

AFFIDAVIT

STATE OF COLORADO)

COUNTY OF JEFFERSON)

I hereby certify that on this 6th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared John L. Simpson, who has produced his Texas driver's license as identification, and he acknowledged before me that he provided the answers to Interrogatory Nos. 1-3 in STAFF'S FIRST SET OF INTERROGATORIES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P. in Docket No. 140110-EI, and that the responses are true and corrected 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 August, 2014.

John L. Simpson

John L. Simpson

Oscar Castrejon

Notary Public
State of Colorado

My Commission Expires:

OSCAR CASTREJON
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20124058579
MY COMMISSION EXPIRES AUGUST 31, 2016

113

Calpine's responses to Staff's Second Set of Interrogatories, Nos. 5-6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 113
PARTY: STAFF
DESCRIPTION: Calpine's responses to Staff's Second Set of Interrogatories, Nos. 5-6.
[Bates Nos. 00327-00333]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI SERVED: AUG. 20, 2014

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P. (NOS. 5-6)

Calpine Construction Finance Company, L.P. ("Calpine") hereby files its responses to Staff's Second Set of Interrogatories (Nos. 5-6), which were propounded on Calpine on August 14, 2014. All of Calpine's responses are subject to Calpine's general objections to Staff's interrogatories, which Calpine served on August 20, 2014, and Calpine does not waive any such objections.

RESPONSES TO SPECIFIC INTERROGATORIES

Interrogatories for Witness David Hunger, Ph.D.:

5. On page 13 of your direct testimony, you note that there are "many" examples of FERC approving mergers involving no change in operational control.

a. Please identify examples of any such cases beyond those listed.

Calpine's Response:

Assuming that "mergers" is intended to include acquisitions or projects as well as mergers of companies, Dr. Hunger has identified eight other cases beyond those listed:

Puget Sound Energy, Inc. Docket No. EC10-5-000. 129 FERC ¶ 62,148. 2009.

San Diego Gas & Electric Company. Docket No. EC11-102-000 136 FERC ¶ 62,261. 2011.

PPL Generation LLC and AES Ironwood, L.L.C. 139 FERC ¶ 62,022 Docket No. EC12-76-000. 2012.

Virginia Electric and Power Company 110 FERC ¶62,077 Docket No. EC05-24-000. 2005.

Virginia Electric and Power Company 120 FERC ¶ 62,132 Docket No. EC07-118-000. 2007.

Black Hills Wyoming, Inc. 123 FERC ¶ 62,236, Docket No. EC08-88-000. 2008.

Puget Sound Energy, Inc. 123 FERC ¶ 62,097, Docket No. EC08-42-000. 2007.

Public Service Company of Colorado 132 FERC ¶ 62,032 Docket No. EC10-71-000. 2010.

b. In these cases, would mitigation have likely been required if there had been a direct transfer, as opposed to one following the execution of a Purchase Power Agreement (PPA)?

Calpine's Response:

It is difficult to say what FERC would have done because these applications were all approved under Delegated Authority. FERC has the authority to "delegate" its statutory authority to its Staff (in particular, Office Directors) and frequently exercises that option in cases that are not protested and do not present issues of first impression. In such approvals, FERC does not state its reasoning in the order; rather it states the facts as described by the applicants and simply approves the application. It is safe to say that each of these cases would have had its own set of facts which would have determined whether mitigation would have been deemed necessary by FERC, had there been no PPA in place. However, in the cases listed above, the applicants did not need to present an argument about any mitigating circumstances because they relied on the argument that the plant being acquired was already under the functional control of the buyer, and therefore the transaction would not adversely affect competition.

I cannot say with certainty what FERC would have done in these cases, i.e., if there had not been a PPA preceding the acquisition, nor is it possible to offer an assessment of how likely is it that FERC would or would not have required mitigation. FERC has frequently stated that it does not blindly follow the screens and will consider the particular facts of the case when analyzing a transaction's potential effect on competition in determining whether mitigation would be required. In its Supplemental Policy Statement regarding evaluations of mergers or acquisitions under Section 203 of the Federal Power Act, FERC stated the following:

> In fact, as noted above, the Commission does look beyond the change in HHI in its analysis of the effect on competition in both horizontal and vertical mergers. The change in HHI serves as a screen to identify those transactions that could potentially harm competition. If the screen is failed, then, as discussed in paragraph 59 above, the Commission examines the factors that could affect competition in the relevant market. Specifically, in these circumstances the Commission typically considers a case-specific theory of competitive harm, which includes, but is not limited to, an analysis of the merged firm's ability and incentive to withhold output in order to drive up prices.[1]

Consistent with that statement, in orders on generation acquisitions by vertically-integrated utilities in their home Balancing Authority Areas (BAAs), FERC has looked beyond the screen failures to the facts of the case, and approved at least some transactions. For example, in *Nevada Power* (Docket No. EC13-96-000, 2013), a case involving the acquisition of a

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[1] FPA Section 203 Supplemental Policy Statement at P65 (2007).

generating facility without a PPA FERC articulated four factors that, when taken together, demonstrated that Nevada Power would not have the ability and incentive to withhold output in order to drive up the market price, and accordingly led FERC to not require mitigation in that case. The factors were:

- Baseload capacity is difficult and uneconomic to withhold;
- Nevada Power was required to fully credit any profits from wholesale sales to retail customers through a fuel adjustment clause, removing any incentive for Nevada Power to raise prices;
- The proposed transaction would not result in the elimination of a competitor, since the seller has not sold into the Nevada Power or Sierra Pacific BAA;
- Nevada Power already has significant control over the output of Unit 4 during peak periods.

Thus, with regard to the eight cases listed above, given FERC's policy and practice, I can only say that FERC might or might not have required mitigation, and that each case would have been determined on its own facts.

c. Are there any examples of FERC still requiring a market screen analysis or mitigation despite operational control not changing during a merger? If so, please identify any such cases.

Calpine's Response:

Dr. Hunger is not aware of any such cases.

6. On page 15 of your direct testimony, you note that you are aware of "at least one case" of FERC approving a merger at the commencement of the PPA.

a. Please identify any other examples beyond the one listed.

Calpine's Response:

Dr. Hunger is not aware of any such cases.

b. Are you aware of any cases of FERC denying a merger or requiring mitigation in such a scenario? If so, please identify any such cases.

Calpine's Response:

Dr. Hunger is not aware of any such cases.

114

NRG's responses to Staff's First Set of Interrogatories, Nos. 1-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 114
PARTY: STAFF
DESCRIPTION: NRG's responses to Staff's First Set of Interrogatories, Nos. 1-3. [Bates Nos. 00334-00341]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	Docket No. 140110-EU
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	Docket No. 140111-EI Submitted: August 13, 2014

NRG FLORIDA LP'S
RESPONSE TO STAFF'S
FIRST SET OF INTERROGATORIES (NOS. 1-3)

** Redacted **

Pursuant to Rule 28-106.206, Fla. Admin. Code, Rule 1.340, Fla. R. Civ. P., and the Order Establishing Procedure in this docket, NRG Florida LP ("NRG") hereby responds to the above-referenced interrogatories in the above-referenced dockets. NRG's responses herein are subject to and without waiver of its August 4, 2014, Objections to such interrogatories, which are incorporated herein for all purposes:

INTERROGATORIES

1. Has NRG sought a statement from the FERC regarding the impact on market power if DEF purchasing the Osceola Facility?

    a. If yes, please provide FERC's response.

    b. If no, why not?

    RESPONSE:

    No. FERC does not issue advisory opinions regarding the market power impact of possible future transactions; its five-step forward-looking acquisition review process (described at pages 7-11 of Dr. John Morris's direct testimony) is only performed upon application by the utility. Accordingly, FERC has neither reviewed nor rejected any of the proposals made by NRG and rejected by DEF.

2. On page 11 of witness John Morris' testimony the witness indicates that DEF witness Julie Solomon did not consider a case in which DEF first signed a long term contract for the Osceola facility and at a later date decided to purchase the facility. Did NRG present a proposal in which DEF would first sign a long term contract for the Osceola facility and at a later date purchase the facility? If so please provide a brief summary of the proposal including the dates the proposal was submitted.

RESPONSE:

Yes. DEF advised NRG that its proposal was rejected in February 2014. However, not until March did DEF advise NRG that DEF had market power concerns associated with the acquisition of the Osceola facility. NRG attempted to gather further information about DEF's concerns through continued negotiations, and in May 2014, NRG offered options in an attempt to address DEF's objections, including a PPA-to-Acquisition proposal. Thereafter, the parties continued to negotiate such proposal, with NRG ultimately offering DEF a formal term sheet in June 2014. At no time during the negotiations did Duke indicate to NRG that it was too late for Duke to consider the PPA–to-Acquisition proposal; to the contrary, Duke led NRG to believe that it was interested in exploring such options to address its stated FERC market power concerns.

Under the term sheet proposal, the parties would enter into a **[redacted]** PPA **[redacted]** for 465 MW with a Capacity Charge of **[redacted]** a Variable O&M charge of **[redacted],** and a Start Charge of **[redacted]**. The proposal also provided for an option to extend the PPA for another **[redacted]** term at **[redacted]**. NRG also offered to sell the Osceola facility to DEF for **[redacted]**, which is less than **[redacted]** of the capital cost of DEF's self-build projects, or **[redacted]** compared to an estimated $661/kW for DEF's projects. Obviously, it took several highly questionable and creative "adjustments" by Duke to close this huge price gap between NRG Osceola and DEF's self-build project.

DEF refused to consider NRG's offer unless NRG agreed to pay for a **[redacted]** deposit DEF had already paid toward the Suwannee turbines. Notably, DEF **[redacted]* * well before advising NRG its proposal was rejected, and incurred the deposit cost before obtaining Commission approval for the Suwannee project. NRG's Document Request No. 36 to DEF sought verification from regarding the sunk costs claimed by DEF as follows:

> Please provide all documents relevant to any non-refundable costs agreed to or incurred by DEF in connection with the Suwannee Simple Cycle Project, including but not limited to turbine supply agreements.

In response, DEF provided a confidential copy of ** [redacted] ** See, 14LGBRA-NRGPOD4-36-000001 - 000053 COMP SENS CONFIDENTIAL Duke_GE_-_Suwannee_CTG_Agnt_Final.pdf at page 14LGBRA-NRGPOD4-36-000001. ** [redacted] ** See, DEF's response to NRG Document Request No. 6, 14LGBRA-NRGPOD4-36-000057 - 000059 COMP SENS CONFIDENTIAL Exh_C-1__Paynt_and_Term_Sched.pdf Further, ** [redacted] ** revealed that DEF ** [redacted] ,** See DEF's Supplemental Response to NRG's Document Request, 14LGBRA-NRGPOD4-36-000080 - 000734 COMP SENS CONFIDENTIAL Exhibit_B-1__Vendor_Firm_Proposal.pdf at page 14LGBRA-NRGPOD4-36-000083.

Further, DEF did not evaluate the cost of NRG's ** [redacted] ** term sheet offer against the cost of the Suwannee Project. Instead, DEF compared the cost of ** [redacted] ** plus the cost of building a "generic combustion turbine project" at the end of that time – even though circumstances may not warrant building additional combustion turbine generation in the 2024 time frame. Although Mr. Borsch stated in his deposition on August 11, 2014, that this additional cost was intended to require NRG to pay for deferral of the Suwannee project, the "generic" project was based on GE7FA.05 turbines, which are more expensive than the GE7FA.03 units in the Suwannee Project. The net effect was to add costs to the NRG PPA proposal which necessarily made the Suwannee project appear less expensive than NRG's proposal, which is not the case.

Finally, DEF insisted that firm natural gas transportation at above-market prices was required to operate the Osceola facility, despite that the facility is a peaker; has operated reliably during its life based upon secondary firm, non-firm and spot market gas transportation (as needed); and, is dual-fuel capable, able to operate on No. 2 oil with 3 million gallons stored on site. When DEF loaded NRG's proposal with all of these additional costs, among others, the result was to render it economically infeasible. Therefore, negotiations between the parties ended in mid-July 1, 2014. In short, DEF did not seriously attempt to develop a mutually acceptable arrangement with NRG, but rather focused on how it could reject any and all of NRG's offerings.

3. Referring to Page 9, lines 6-7 of witness Jeffrey Pollock's direct testimony, please explain in detail how witness Pollock determined that DEF erred when it excluded incremental fuel delivery and service costs from DEF's analysis of self-build projects.

RESPONSE:

DEF's failure to include any fuel delivery and service costs in its analysis of its self-build projects is erroneous because it does not provide an "apples-to-apples" comparison between DEF's proposed self-build generation projects and other alternatives. A proper comparison would include all costs associated with each generation option.

DEF, like NRG or any other provider, will necessarily incur fuel delivery and service costs to provide natural gas to its self-build projects. These costs will not be zero. Ignoring or excluding these costs on the self-build projects while including them on third-party projects not only inappropriately and unfairly biases the cost-effectiveness analysis to favor the self-build projects over NRG and other third-party projects, but more importantly makes it virtually impossible for the Commission to determine the true cost of Duke's projects or whether they are the most cost-effective alternative as Duke alleges.

AFFIDAVIT OF JOHN R. MORRIS

CITY OF WASHINGTON

DISTRICT OF COLUMBIA

I hereby certify that on this 19th day of August, 2014, before me, an officer duly authorized to take acknowledgments, personally appeared JOHN R. MORRIS, who is personally known to me, and he acknowledged before me that he/she provided the answers to Interrogatory No. 1 from STAFF'S FIRST SET OF INTERROGATORIES TO NRG FLORIDA LP (NOS. 1-3) and Interrogatory No. 4 from STAFF'S SECOND SET OF INTERROGATORIES TO NRG FLORIDA LP (NO.4) in Docket No(s). 140110-EI, 140111-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 on this 19th day of August, 2014.

Lori J. Rodriguez

Notary Public

My Commission Expires:

Lori J. Rodriguez
District of Columbia, Notary Public
My Commission Expires
June 30, 2018

LORI J. RODRIGUEZ NOTARY PUBLIC COMMISSION EXPIRES 06-30-2018 DISTRICT OF COLUMBIA

AFFIDAVIT

STATE OF LOUISIANA)

PARISH OF EAST BATON ROUGE)

I hereby certify that on this 19th day of August 2014, before me, an officer duly authorized in the State and Parish aforesaid to take acknowledgments, personally appeared GORDON D. POLOZOLA, who is personally known to me, and he acknowledged before me that he provided the answer to Interrogatory No. 2 in STAFF'S FIRST SET OF INTERROGATORIES TO NRG FLORIDA LP (NOS. 1-3) in Docket No(s). 140110-EI, 140111-EI, and that the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and Parish aforesaid as of this 19th day of August 2014.

Notary Public
State of Louisiana #01332

My Commission Expires: at death

AFFIDAVIT

STATE OF MISSOURI)

COUNTY OF ST. LOUIS)

I hereby certify that on this 19th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JEFFRY POLLOCK, who is personally known to me, and he acknowledged before me that he provided the answer to Interrogatory No. 3 in STAFF'S FIRST SET OF INTERROGATORIES TO NRG FLORIDA LP (NOS. 1-3) in Docket No(s). 140110-EI, 140111-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 19th day of August, 2014.

Notary Public
State of Missouri

My Commission Expires:
Apr. 25, 2015

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2015
Commission Number: 11390610

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NRG's responses to Staff's Second Set of Interrogatories, No. 4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 115
PARTY: STAFF
DESCRIPTION: NRG's responses to Staff's Second Set of Interrogatories, No. 4. [Bates Nos. 00342-00346]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	Docket No. 140110-EU
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	Docket No. 140111-EI Submitted: August 19, 2014

NRG FLORIDA LP'S
RESPONSE TO STAFF'S
SECOND SET OF INTERROGATORIES (NO. 4)

Pursuant to Rule 28-106.206, Fla. Admin. Code, Rule 1.340, Fla. R. Civ. P., and the Order Establishing Procedure in this docket, NRG Florida LP ("NRG") hereby responds to the above-referenced interrogatories in the above-referenced dockets.

INTERROGATORIES

4. Are you aware of any FERC cases in which FERC acted in a matter that would support the scenarios you describe in Section 5 of your direct testimony, or ruled in a case making the same or similar arguments? If so, please identify any such cases.

RESPONSE:

Yes. FERC has historically considered all the relevant facts in its competitive assessments. For example, *Entergy Gulf States* (121 FERC ¶ 61,182 (2007)) dealt with an Entergy acquisition of the Calcasieu peaking facility, similar to an acquisition by Duke Energy Florida of NRG's Osceola facility. Although an intervenor claimed that a proper FERC screen analysis showed multiple screening violations, FERC nevertheless approved Entergy's acquisition of peaking capacity. FERC found the acquisition acceptable despite the screen violations because the additional capacity was necessary for Entergy to meet its load and reliability conditions. Similarly Duke claims here that capacity comparable to that provided by NRG's Osceola facility is necessary to meet its load and reserve requirements in Florida.

Another example is *Duke Energy Corporation* (113 FERC ¶ 61,297 (2005)), which dealt with Duke's acquisition of Cinergy. Duke's application admitted one base case available economic activity (AEC) screen violation, just as Duke claims one AEC screen violation in the Winter Super Peak base case for a Duke acquisition of NRG's Osceola facility (Docket 140111-EI, Solomon direct testimony at page 20, line 14 through page 21, line 4; Exhibit JS-9). FERC approved the acquisition of Cinergy, however, because there was little evidence that Cinergy competed in Duke's Carolina balancing authority area (BAA). Hence, the Duke acquisition of Cinergy did not involve losing Cinergy competition in the Carolinas and was deemed in the public interest. Similarly here, NRG's Osceola facility rarely operates during the winter season in which Duke claims a FERC screen violation, and moving the combustion turbines out of the BAA or NRG signing a long-term contract to a buyer outside of the BAA is competitively similar. In addition, Duke averages less than 7 mega-Watts per hour in off-system wholesale sales. In other words, whether by lack of competition in the current situation, NRG physically moving the combustion turbines from Osceola, or NRG contractually moving the Osceola facility to another BAA, NRG Osceola does not have meaningful competition with Duke in the period of the alleged screen violation (Winter Super Peak). Because of the lack of competition, FERC would be expected to approve Duke's acquisition of NRG's Osceola peaking facility.

FERC Screen results should match actual commercial realities. When they do not (and the screens proffered by Duke do not because they allege screen violations in the Winter Super Peak period when the companies do not compete), then the commercial realities dictate the result that there is no substantial loss in competition and the acquisition would be approved. As an alternative to showing screen violations and then explaining why the violations do not indicate a loss of competition, the calculation of the screens could be revised to reflect the commercial realities and no screen violation, as explained in Section 5 of my testimony. Further, Ms. Solomon conceded in her rebuttal testimony that "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" (Docket 140111-EI, Solomon rebuttal, pg. 12, lines 7-10) and therefore a PPA-to-acquisition structure would remove concerns regarding FERC market screen failure.

AFFIDAVIT OF JOHN R. MORRIS

CITY OF WASHINGTON

DISTRICT OF COLUMBIA

I hereby certify that on this 19th day of August, 2014, before me, an officer duly authorized to take acknowledgments, personally appeared JOHN R. MORRIS, who is personally known to me, and he acknowledged before me that he/she provided the answers to Interrogatory No. 1 from STAFF'S FIRST SET OF INTERROGATORIES TO NRG FLORIDA LP (NOS. 1-3) and Interrogatory No. 4 from STAFF'S SECOND SET OF INTERROGATORIES TO NRG FLORIDA LP (NO.4) in Docket No(s). 140110-EI, 140111-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 on this 19th day of August, 2014.

Lori J. Rodriguez

Notary Public

My Commission Expires:

Lori J. Rodriguez
District of Columbia, Notary Public
My Commission Expires
June 30, 2018

LORI J. RODRIGUEZ NOTARY PUBLIC COMMISSION EXPIRES 06-30-2018 DISTRICT OF COLUMBIA

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DEF's responses to Staff's First Production of Documents, Nos. 1-10

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 116
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's First Production of Documents, Nos. 1-10. See also files contained on St...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of cost effective generation alternative to meet need prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI DATED: JULY 15, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO DUKE ENERGY FLORIDA, INC. (NOS. 1-11)

Duke Energy Florida, Inc. ("DEF") responds to Staff of the Florida Public Service Commission's ("Staff") First Request for Production of Documents to Duke Energy Florida, Inc. (Nos. 1-11) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General and Specific Objections to Staff's First Request for Production of Documents (Nos. 1-11), served on July 7, 2014, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

1. Referring to page 10, lines 14 - 19, of witness Kevin Delehanty's direct testimony, please provide a copy of all the documents and data sources that DEF or its consultants employed to derive the carbon cost forecasts for the instant case.

RESPONSE:

Please see documents attached in Bates range 14LGBRA-STAFFPOD1-1-000001 through 14LGBRA-STAFFPOD1-1-000241.

2. Please provide any documentation or analyses in support of your answer to Interrogatory No. 3.

RESPONSE:

The data was extracted from a company system reporting tool and provided in an excel table. The spreadsheet file is attached as a document entitled "140111_Staff_1st_POD_2.xlsx" and bears Bates Number 14LGBRA-STAFFPOD1-2-000001 through 14LGBRA-STAFFPOD1-2-000002.

3. Please provide the documents identified in response to Interrogatory Nos. 5, 6, 7 and 9.

RESPONSE:

Please see documents produced in Bates range 14LGBRA-STAFFPOD1-3-000001 through 14LGBRA-STAFFPOD1-3-000049.

4. Please provide any documents and work papers that support your response to Interrogatory Nos. 12 and 13.

RESPONSE:

See 18 CFR §33.11 referenced in Interrogatory 12. The response to Interrogatory 13 relied on Exhibits BMHB-10 and BMHB-11 from Mr. Borsch's testimony.

5. Referring to DEF witness Solomon's direct testimony, page 17, lines 20-23, please provide the 2008-2009 Simultaneous Import Limit (SIL) data.

RESPONSE:
The SIL values were provided in *Order on Simultaneous Transmission Import Limit Values for the Southeast Region*, Docket Nos. ER10-2566, *et al.*, February 24, 2012, Attachment A. In the Competitive Screen Analysis, the average of the Spring and Fall values were used for the Shoulder time periods.

Please see document attached in Bates range 14LGBRA-STAFFPOD1-000001 through 14LGBRA-STAFFPOD1-000007.

6. Please provide the Competitive Analysis Screen, and associated work papers in Excel format with formulas intact and cells unlocked, from which the "AEC Facts" on Exhibit (JS-6) were extracted.

RESPONSE:

See Response to NRG's 2nd Document Request 24.

7. Please provide work papers and supporting documents in Excel format with formulas intact and cells unlocked, for Exhibits (JS-9) through (JS-12).

RESPONSE:

See Response to NRG's 2nd Document Request 27.

8. Referring to DEF witness Solomon's direct testimony at page 24, lines 22-23, please provide the results of the sensitivity analyses conducted using higher SILs. Please identify the SIL values used in the base case analyses and contrast them with the SIL values used in these sensitivity analyses.

RESPONSE:

See files: "DPT Analysis with Alternative SIL Values.xlsx" and "SIL Values in DPT Analyses.xlsx" bearing Bates Numbers 14LGBRA-STAFFPOD1-8-000001 through 14LGBRA-STAFFPOD1-8-000007.

9. Referring to DEF witness Solomon's direct testimony, page 27, lines 21-23, please provide all work papers and supporting documents that underlie the estimated 600 to 800 MWs of additional transmission import capability required.

RESPONSE:

The model was provided in Response to NRG's 2nd Document Request 27. The amounts of increased import capability required for each time period are shown in tab name "Wkp-SIL DEF Market". The analysis was completed by an iterative process, increasing the SIL until a solution was identified.

Summaries of the results are provided in file name: "DEF-DPT Results with Tx Mitigation.xlsx" bearing Bates number 14LGBRA-STAFFPOD1-9-000001 through 14LGBRA-STAFFPOD1-9-000006.

10. Referring to DEF witness Solomon's direct testimony, page 27, line 23, through page 28, lines 1-2, please provide all work papers and supporting documents that underlie the estimated in excess of 1,000 MWs of additional transmission import capability required.

RESPONSE:
The model was provided in Response to NRG's 2nd Document Request 27.

The amounts of increased import capability required for each time period are shown in tab name "Wkp-SIL DEF Market". The analysis was completed by an iterative process, increasing the SIL until a solution was identified.

Summaries of the results are provided in file name: "DEF-DPT Results with Tx Mitigation.xlsx" produced in response to Request 9 above.

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Dianne M. Triplett
Associate General Counsel
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/s/ Blaise N. Gamba
James Michael Walls
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DEF's responses to Staff's Third Production of Documents, Nos. 14-16

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 117
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Third Production of Documents, Nos. 14-16. See also file contained on St...

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 Served: August 12, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS TO DUKE ENERGY FLORIDA, INC. (NOS. 14-18)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Third Request for Production of Documents to Duke Energy Florida, Inc. (Nos. 14-18) as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to Staff's Third Request for Productions of Documents (Nos. 14-18), served on August 4, 2014, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

14. Please provide a copy of the solicitation for proposals for the Purchased Power Agreement (PPA) described on page 32 of witness Benjamin Borsch's testimony.

RESPONSE:

Please see document attached in Bates range 14LGBRA-STAFFPOD3-14-000001 through 14LGBRA-STAFFPOD3-14-000003.

15. Please provide a copy of DEF's request for renewed proposals for PPAs as described on page 33 of witness Borsch's testimony.

RESPONSE:

Those bidders that DEF requested refreshed proposals from were contacted individually via phone and no new solicitation was issued.

16. Please provide a copy of DEF's solicitation for potential generation facility acquisitions as described at lines 10-12 on page 33 of witness Borsch's testimony.

RESPONSE:

On or about the week of September 9, 2013, DEF made verbal contact with Calpine and NRG. During those calls, DEF informed them that if they were willing to offer their plants for acquisition rather than just in PPA, DEF may be willing to consider an acquisition. This resulted in preliminary acquisition offers from NRG and Calpine in October, 2013.

/s/ *Blaise N. Gamba*

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DEF's responses to Staff's Fifth Production of Documents, Nos. 20-21

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 118
PARTY: STAFF
DESCRIPTION: DEF's responses to Staff's Fifth Production of Documents, Nos. 20-21. See also file contained on St...

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 20, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO
<u>STAFF'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 20-21)</u>

Duke Energy Florida, Inc. ("DEF") responds to Staff's Fifth Request for Production of Documents (Nos. 20-21) as follows:

<u>GENERAL AND SPECIFIC OBJECTIONS</u>

DEF incorporates and restates its General Objections to Staff's Fifth Request for Production of Documents (Nos. 20-21), served on August 18, 2014, as if those objections were fully set forth herein.

<u>DOCUMENTS REQUESTED</u>

20. Please provide any documents that support your response to Interrogatory No.1.

<u>RESPONSE</u>:

In responding to this request DEF assumes the reference is to Staff's 6th Interrogatories to DEF, No. 92.

There are no responsive documents.

21. Please provide any documents that support your response to Interrogatories Nos. 1.a. and 1.b.

<u>RESPONSE</u>:

In responding to this request DEF assumes the reference is to Staff's 6th Interrogatories to DEF, Nos. 93a and 93b.

Please see documents attached in Bates range 14LGBRA-STAFFPOD5-21-000001 through 14LGBRA-STAFFPOD5-21-000263.

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DEF's Supplemental response to NRG's First Production of Documents, No. 8

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 119
PARTY: STAFF
DESCRIPTION: DEF's Supplemental response to NRG's First Production of Documents, No. 8. See also files contained...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	Docket No. 140111-EI Served: July 11, 2014

DUKE ENERGY FLORIDA, INC.'S *SUPPLEMENTAL* RESPONSES TO NRG FLORIDA LP'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS NOS. 1-17 TO DUKE ENERGY FLORIDA, INC.

Duke Energy Florida, Inc. ("DEF") provides this supplemental response to NRG Florida LP's First Request for Production of Documents Nos. 1-17 to Duke Energy Florida, Inc., specifically as to Request Numbers 1, 4-16, and states as follows:

GENERAL AND SPECIFIC OBJECTIONS

DEF incorporates and restates its General Objections to NRG's First Request for Productions of Documents Nos. 1-17, served on June 23, 2014, as if those objections were fully set forth herein.

DOCUMENTS REQUESTED

8. As related to Mr. Borsch's testimony, for each third-party proposal considered by Duke as an alternative to self-build, please provide the detailed economic evaluation, including inputs, data, and analysis performed by Duke for each proposal compared to Duke's self-build generation alternatives.

RESPONSE:

The detailed inputs, data and results from the models utilized by DEF are provided in response to Request Number 7. The analysis resulting in the tables presented in Exhibits BMHB-8, BMHB-9, BMHB-10 and BMHB-11 were developed using the spreadsheet models attached in response to this request. Please note that a mathematical error was observed in the spreadsheet supporting Exhibit BMHB-8, and that error has been corrected. A copy of the resulting updated exhibit BMHB-8 is being provided with this response. DEF will also file an updated Exhibit BMHB-8 in this docket. Please see documents attached bearing Bates numbers 14LGBRA-NRGPOD1-8-DOC 1 through 14LGBRA-NRGPOD1-8-DOC 2. Please see also documents produced in response to NRG's First Set of Interrogatories No. 28.

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Calpine's responses to Staff's First Production of Documents, Nos. 1-2

<u>See also</u>: Files on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 120
PARTY: STAFF
DESCRIPTION: Calpine's responses to Staff's First Production of Documents, Nos. 1-2. See also files contained on...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	DOCKET NO. 140110-EI
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	DOCKET NO. 140111-EI SERVED: AUG. 20, 2014

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.'S RESPONSES TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P. (NOS. 1-2)

Calpine Construction Finance Company, L.P. ("Calpine") hereby responds to Staff's First Request for Production of Documents (Nos. 1-2).

DOCUMENTS REQUESTED

1. Please provide copies of any cases identified in response to Interrogatories Nos. 5.a. and 5.c.

Calpine's Response:

Calpine will produce documents responsive to this request.

2. Please provide copies of any cases identified in response to Interrogatories Nos. 6.a. and 6.b.

Calpine's Response:

No such documents exist.

Respectfully submitted this 20th day of August, 2014.

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Attorneys for Calpine Construction
Finance Company, L.P.

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NRG's responses to Staff's Second Production of Documents, No. 2

See also: File on Staff's Exhibit CD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 121
PARTY: STAFF
DESCRIPTION: NRG's responses to Staff's Second Production of Documents, No. 2. See also file contained on Staff ...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	Docket No. 140110-EU
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	Docket No. 140111-EI Submitted: August 19, 2014

NRG FLORIDA LP'S
RESPONSE TO STAFF'S
SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 2)

Pursuant to Rule 28-106.206, Fla. Admin. Code, Rule 1.340, Fla. R. Civ. P., and the Order Establishing Procedure in this docket, NRG Florida LP ("NRG") hereby responds to the a bove-referenced document request in the above-referenced dockets.

DOCUMENTS REQUESTED

2. Please provide copies of any cases identified in response to Interrogatory No. 1.

RESPONSE:

NRG will provide the cases identified in its Response to Staff Interrogatory No. 4 in a document labeled "2014.08.19.NRG.Doc.45.001331-001388.Staff POD 2.pdf."

Respectfully submitted this 19th day of August, 2014.

/s/ Marsha E. Rule

Marsha E. Rule, Esq.
Fla. Bar No. 0302066
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121 FERC ¶ 61,182
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Entergy Gulf States, Inc. and Calcasieu Power, LLC — Docket No. EC07-70-000

ORDER AUTHORIZING DISPOSITION AND ACQUISITION OF JURISDICTIONAL FACILITIES

(Issued November 19, 2007)

1. On March 15, 2007, as supplemented on April 10, 2007, Entergy Gulf States, Inc. (Entergy Gulf States) and Calcasieu Power, LLC (Calcasieu Power) (collectively, Applicants) filed an application under section 203 of the Federal Power Act (FPA).[1] Applicants request Commission authorization for a disposition and acquisition of jurisdictional facilities associated with the sale of a natural gas-fired combustion turbine generating facility (Facility) by Calcasieu Power to Entergy Gulf States.

2. Section 203(a)(4) requires the Commission to approve a transaction if it determines that the transaction will be consistent with the public interest. Our analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition, (2) the effect on rates, and (3) the effect on regulation.[2] Section 203 also requires the Commission to find that the

[1] 16 U.S.C. § 824b (2000), *amended by* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594 (2005) (EPAct 2005).

[2] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, 72 Fed. Reg. 42,277 (Aug. 2, 2007), FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest."[3] The Commission's regulations establish verification and informational requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or pledge or encumbrance of utility assets.[4]

I. Background

A. Applicants

3. Entergy Gulf States is a public utility that owns and operates generation, transmission, and distribution facilities, and provides electricity for approximately 720,000 retail customers in Louisiana and Texas. It is a wholly-owned subsidiary operating company of Entergy Corporation (Entergy). Entergy Gulf States thus is affiliated with the other Entergy Operating Companies,[5] as well as Entergy Services, Inc., the service company that performs various administrative, legal, and operational functions for the Energy Operating Companies, including acting as their agent with respect to certain contracts and in proceedings at the Commission.

4. Calcasieu Power is a public utility that has Commission authorization to make wholesale sales of power at market-based rates.[6] It owns certain interconnection facilities but no other transmission assets. Following the sale of the Facility, Calcasieu Power will own no generation assets, transmission interconnection facilities, or jurisdictional assets. Calcasieu Power's ultimate parent is Dynegy Inc. (Dynegy). Through its affiliates, Dynegy produces and sells electric energy, capacity, and ancillary services in U.S. markets. Dynegy's power generation portfolio consists of approximately 12,000 megawatts (MWs) of baseload, intermediate, and peaking power plants fueled by a mix

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[3] 16 U.S.C. § 824b(a)(4) (2000), *amended by* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594, 982-83 (2005).

[4] 18 C.F.R. § 33.2 (2007).

[5] The Entergy Operating Companies are Entergy Gulf States, Entergy Arkansas, Inc., Entergy Louisiana, LLC, Entergy Mississippi, Inc., and Entergy New Orleans, Inc.

[6] *Calcasieu Power, LLC,* 90 FERC ¶ 61,164 (2000).

of coal, fuel oil, and natural gas. Calcasieu Power's affiliate, Dynegy Power Marketing, Inc., markets the output from Dynegy's generation portfolio.

B. The Proposed Transaction

5. The Facility is a 310 MW simple-cycle generating facility consisting of two combustion turbine generators. It is located in Calcasieu Parish, Louisiana and is connected to Entergy Gulf States' 230 kV transmission system.[7] As part of the proposed transaction, Entergy Gulf States will assume the existing Interconnection and Operating Agreement (IA). Applicants state that the Facility is needed to improve Entergy system reliability and will provide peaking and reserve capacity that can be scheduled within the current day in the case of generation failures, when there is unexpected demand, or to avoid purchases.[8]

6. Entergy Gulf States, Calcasieu Power, and Dynegy Holdings, Inc. entered into an asset purchase agreement for the sale of the Facility for more than $10 million (Purchase Agreement). Entergy Gulf States and Calcasieu Power also entered into the Substation and Power Line Transfer Agreement (Transfer Agreement). These two Agreements establish the terms and conditions of the transaction. The Transfer Agreement provides for the transfer of certain interconnection facilities not included under the Purchase Agreement.

7. Entergy Gulf States and certain of the other Entergy Operating Companies currently purchase capacity and energy from the Facility under two call option agreements.[9] As part of the proposed transaction, the parties would modify these two

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[7] The Facility also includes related transmission interconnection facilities owned by Calcasieu Power, pipeline interconnection facilities, and equipment, structures, improvements, and appurtenances.

[8] Applicants state that based on the portfolio of existing long-term resources, the Entergy Operating Companies are more than 3,000 MW short of their projected 2008 reliability requirement. Assuming that no additional resources are added, they will be over 5,000 MW short of their reliability requirement by 2012. Entergy Gulf States' portfolio of long-term resources is nearly 1,200 MW short of its projected 2008 peak demand plus reserve requirement and, assuming no additional resources are added, this deficiency is expected to reach about 1,750 MW by 2012. Application at 7-8.

[9] A call option is a financial contract between two parties, the buyer and the seller of this type of option. The buyer of the option has the right, but not the obligation, to buy an agreed quantity of a particular commodity or financial instrument from the seller at a

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long-term purchase power agreements. The end result would be a tolling arrangement for the full output of the Facility.[10]

II. Notices and Responsive Pleadings

8. Notice of Applicants' original filing was published in the *Federal Register*, 72 Fed. Reg. 15,133 (2007), with protests and interventions due on or before April 30, 2007.

9. On April 6, 2007, Commission staff issued a letter requesting additional data to verify Applicants' "first tier markets" results of their horizontal competition analysis under Appendix A of the *Merger Policy Statement*. On April 10, 2007, Applicants filed the information with the Commission.

10. On April 30, 2007, Occidental Chemical Corporation (Occidental) filed a motion to intervene and protest. The Arkansas Public Service Commission (Arkansas Commission) filed a notice of intervention and protest. The Mississippi Public Service Commission, the Louisiana Public Service Commission (Louisiana Commission), and the City Council of the City of New Orleans filed notices of intervention with no substantive comments. The Louisiana Energy Users Group filed a motion to intervene on April 26, 2007 with no substantive comments.

11. On May 15, 2007, Applicants filed an answer to the protests filed by Occidental and the Arkansas Commission.

12. On June 7, 2007, Commission staff issued a letter (Staff Letter) requesting Applicants to supply an analysis of the effect of the proposed transaction on the West of the Atchafalaya Basin (WOTAB) market for both economic capacity and available economic capacity for the same time periods as those dealt with in the application. Staff also requested that Applicants explain the ratepayer protections they will provide in order to ensure that the transaction will not adversely affect wholesale rates.

13. On June 28, 2007, Applicants filed a response to the Staff Letter. Notice of this filing was published in the *Federal Register*, 72 Fed. Reg. 41,067 (2007), with protests and interventions due on or before July 25, 2007. On July 25, 2007, Occidental filed a

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certain time for a certain price. The seller is obligated to sell the commodity or financial instrument should the buyer so decide. The buyer pays a fee, or premium, for this right.

[10] As discussed below, this outcome was described through subsequent filings made by the Applicants. The original application spoke only of "a tolling arrangement for the full output of the Facility until closing of the acquisition." Application at 9.

supplemental protest to Applicants' response to the Staff Letter. On August 9, 2007, Applicants filed an answer to Occidental's supplemental protest.

III. Discussion

A. Procedural Matters

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2007), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

15. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2007), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Applicants' May 15, 2007 answer to the protests filed by Occidental and the Arkansas Commission and their August 9, 2007 answer to Occidental's supplemental protest because those answers have provided information that assisted us in our decision-making process.

B. Substantive Issues – Section 203 Analysis

16. Section 203(a) of the FPA requires the Commission to approve a transaction if the Commission makes two determinations.[11] As discussed above, the Commission first must determine whether the transaction will be consistent with the public interest, which it does by considering the effect of the transaction on competition, rates, and regulation. Second, the Commission must determine whether the transaction will result in

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[11] Applicants state that prior Commission approval of the proposed transaction under FPA section 203(a)(1)(D)(i) is required because the Facility is an existing generation facility with a value of over $10 million that is used to make wholesale sales subject to the Commission's jurisdiction. We note that "value" for these purposes is market value, and market value is rebuttably presumed to be the transaction price. 18 C.F.R. § 33.1(b)(3)(i) (2007). Applicants state that it is not clear whether prior Commission approval under section 203(a)(1)(A) is required for Calcasieu Power's disposition of the transmission interconnection facilities. This is because there is no separately-stated price for these facilities in the Agreements, so the value of the facilities is not known for these purposes. Applicants thus request that the Commission assume jurisdiction over the disposition of such facilities for purposes of the Application. The Commission will not resolve whether it has such jurisdiction for these purposes. In any event, the same statutory standard applies regardless of which subsections apply.

inappropriate cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.

1. Effect on Competition

a. Horizontal Competitive Issues

i. Applicants' Analysis

17. Applicants state that the proposed transaction will not cause any adverse effects on competition. They explain that the Entergy Operating Companies, including Entergy Gulf States and other Entergy affiliates that own generation in the Entergy system control area, are not authorized to make sales at market-based rates in this control area. As a result, Applicants state that these companies would not be able to increase the prices at which they make sales, and wholesale competition would not be affected, even if their market power was enhanced as a result of the proposed transaction. Applicants also state that the Entergy Operating Companies are net purchasers of capacity and energy.

18. Applicants state that because the Entergy Operating Companies are not members of a regional transmission organization (RTO), they analyzed the Entergy system control area as a separate destination market and also analyzed all relevant first-tier control areas, i.e., all control areas that are directly interconnected with the system control area.[12]

19. Applicants further explain that the Facility is a peaking facility that operates primarily in the highest-load hours of the year. They state that the Facility's operating costs are comparable to those of other modern peaking facilities, but that its variable operating costs are high compared to other baseload and mid-merit generation in the region. Consistent with the Competitive Analysis Screen, Applicants considered the effect of the proposed transaction over a range of system conditions and determined that the only relevant system conditions are those in which peaking units such as the Facility are economic. Applicants state that they further concluded that the Facility is economic only in three periods and that these are the only periods when Herfindahl-Hirschman Index (HHI) changes can occur.[13] The periods in question are Summer Super Peak 1, Summer Super Peak 2, and Shoulder Super Peak.

20. Applicants performed both an Economic Capacity (EC) and an Available Economic Capacity (AEC) analysis and found some screen failures for the EC measure in

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[12] Application at 12.

[13] *Id.* at 13 and Exh. J-1 at 20.

the Entergy market following the transaction. However, they note that there are no definite plans for retail competition in Texas, Louisiana, Arkansas, Mississippi, and New Orleans. The Entergy Operating Companies thus have no obligation to serve their native load customers, and this makes the EC measure a poor indication of the competitive significance of the proposed transaction. AEC provides a more relevant measure of the market and therefore should be given more weight, as the Commission found in previous cases.[14] Applicants state that the proposed transaction passes the AEC analysis in all relevant time periods and that the post-transaction market shares range from 7.3 percent to 16.6 percent in markets that are not concentrated (i.e., markets that have an HHI of less than 1,000). Applicants assert that the results in the Summer Super Peak 1 and 2 periods are 16.6 percent and eight percent, which compare favorably to the *Duke* market shares in the Summer Super Peak 1 and 2 periods of 23.6 percent and 27.1 percent respectively.

21. Finally, Applicants' analysis of the first-tier markets for both the EC and AEC measures shows that there are no screen failures. Applicants state that their post-acquisition market share ranges from essentially zero percent to about 10.2 percent in these markets and that the screening analysis is passed in all time periods, because all of the HHI changes are in the single digits, and none exceed 7 points in any market where the post-acquisition HHI is above 1,000.

ii. Protests

22. Occidental argues that the geographic market used in Applicants' delivered price test (DPT) analysis is unrealistically large because it does not reflect the fact that some customers cannot reach competing supplies due to transmission limitations. It claims that the Entergy transmission system has significant internal transmission constraints that require Entergy to maintain a separate supply portfolio in each of its four sub-regions in order to maintain reliability. Occidental cites documentation by other market participants showing that even small amounts of competing generation cannot participate in wholesale markets. This is because of the prohibitive transmission upgrade costs brought about by Entergy's persistent underinvestment in transmission capacity in its control area.[15] This same study showed 41 instances in which the Webre-Wells 500 kV line was

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[14] *Id.* at 14 (citing *Nevada Power Co.,* 113 FERC ¶ 61,265 (2005) (*Nevada Power*) and *Duke Power Company, LLC,* 117 FERC ¶ 62,094 (2006) (*Duke*)).

[15] Occidental Protest, Attachment 1, Affidavit of David W. DeRamus (DeRamus Affidavit) at 14 (citing Comments of the Louisiana Energy and Power Authority and the Lafayette Utilities System in response to the Department of Energy's Notice of Inquiry, "Consideration for Transmission Congestion Study and Designation of National Interest (continued)

the limiting element in System Impact Studies carried out by Entergy in response to requests by entities attempting to wheel power in and out of the WOTAB region.[16] Occidental further cites the Commission's finding that using the Entergy control area as the relevant geographic market in the DPT for Entergy's market-based rate filing required an evidentiary hearing because it was unclear whether there are binding transmission constraints that make it appropriate to define more than one geographic market within the Entergy control area.[17] Occidental remarks that the evidentiary hearing never occurred because Entergy abandoned its request for market-based rate reauthorization within its control area, so the task of defining the relevant geographic markets remains uncompleted.[18]

23. Occidental argues that defining the relevant geographic market to account for transmission constraints internal to the Entergy control area is important because these constraints are more likely to be binding during peak and super-peak periods, when it is economic to dispatch the Facility. Occidental found in another case that a detailed sub-regional DPT analysis showed a more dominant market position than an analysis that relies on the entire Entergy control area as the relevant market.[19]

24. Occidental claims further that Applicants incorrectly modeled the amount of competing generation available in the Entergy control area. It is unclear from Applicants' testimony how they derived 20,506 MWs of rival capacity in the Entergy control area when Entergy's own transmission study report of February 9, 2004, states that 13,900 MWs of merchant generation was expected to be available within the Entergy control area by the summer of 2004.[20] Further, Applicants assume that there are 4,446

Electric Transmission Corridors," published in the *Federal Register* on February 2, 2006. 71 Fed. Reg. 5,660 (LEPA Comments), at 212-224).

[16] *Id.* (citing LEPA Comments at 219).

[17] *Id.* at 6. Occidental references the Commission's finding in *Entergy Services, Inc.*, 111 FERC ¶ 61,507 (2005).

[18] *Id.* at 7.

[19] *Id. See Entergy Services, Inc.*, 111 FERC ¶ 61,507 at P 25 (establishing a trial-type, evidentiary hearing to examine Entergy's DPT for the purpose of determining whether Entergy should be allowed market-based rate authority for transactions in the Entergy control area).

[20] *Id.* at 8.

MWs of simultaneous import capability in summer periods, but the same transmission study report assumes a simultaneous import capability of 3,000 MWs in the summer period. In addition, Occidental claims that it may not be appropriate to include some merchant generation in the relevant market within a sub-region. Generating facilities, such as its own Taft facility, are often unable to get transmission access to the sub-regional market. Occidental further claims that Applicants incorrectly included planned outages during the extreme summer super-peak period, because generators typically do not plan outages during the top one percent of load hours in summer. Making this correction, Occidental finds that Applicants' analysis understates the potential harm to competition caused by the transaction.[21]

25. Occidental also contends that Applicants' AEC analysis is faulty. Occidental's analysis of wholesale transactions delivered into the Entergy control area as reported in 2005 Electronic Quarterly Report filings indicates that Entergy had a 67 percent share of those transactions, yielding an HHI of over 4,600.[22] Applicants' DPT analysis is not verifiable because Applicants did not provide information such as a list of competing generation in the Entergy control area, historical trade data, historical transmission data, long-term purchase and sales data, native load commitments of competing suppliers, information regarding transmission constraints, and work papers regarding the simultaneous import capability computation.[23]

26. Occidental objects to Applicants' reliance on *Nevada Power Co.*[24] and *Westar Energy Inc.*[25] to support the claim that AEC is the more relevant measure. To the contrary, EC analysis provides a better measure of competitive conditions in the short-term non-firm wholesale market than AEC because native load varies from hour to hour, and generation that serves native load in one hour can serve wholesale load in another hour. Occidental observes that in the cases cited, the Commission did not hold that EC is not a valid measure of competition in markets where there is no retail access and no definitive plan for retail access. The determination of whether EC is relevant turns on the market conditions in the particular case. Based solely on DPT screen failures using the

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[21] *Id.* at 9-10.

[22] *Id.* at 10.

[23] *Id.* at 11-12.

[24] 113 FERC ¶ 61,265 (2005).

[25] 115 FERC ¶ 61,228; *order on reh'g*, 117 FERC ¶ 61,011 (2006); *order on reh'g*, 118 FERC ¶ 61,237 (2007).

EC measure, the Commission found in *Oklahoma Gas & Elec. Co.* that, without mitigation, the proposed transaction would harm competition due to an increase in market power.[26]

27. Occidental performed an Appendix A analysis of the proposed acquisition on horizontal competition using the DPT methodology. It relied on 2002-2003 price and cost data used in Entergy's 2004 market-based rate filing. In order to ensure an "apples to apples" comparison with Applicants' results, Occidental updated some of the price and cost data inputs used in its own prior DPT analysis to reflect 2004-2005 price and cost data. Occidental's computations indicate that the Entergy control area and the transmission-constrained WOTAB load pocket in which the Facility is located are highly concentrated markets. Occidental's 2004-2005 analysis shows five screen failures for EC[27] and one screen failure for AEC.[28]

28. Occidental also claims that Entergy's proposed acquisition of the Facility is just one in a series of three Entergy acquisitions of distressed generation assets in the past two years. Including the Facility's 310 MWs of capacity, Entergy will have removed 1,535 MWs of independently-owned generation from the wholesale market and significantly increased its dominant share of generation in its control area. Occidental's cumulative DPT analysis of 2004-2005 data for the cumulative transactions shows EC screen failures in all ten time periods analyzed[29] and AEC failures in three time periods.[30] Occidental concludes that it is important for the Commission to consider Entergy's overall business strategy in assessing whether the transaction is likely to harm competition and whether it is in the public interest. The antitrust agencies (the Department of Justice and the Federal Trade Commission) have been concerned when parties attempt to harm competition through a series of smaller acquisitions. Occidental states that those agencies may review even a small transaction that would otherwise not be subject to review if it has an incrementally negative effect on competition.[31]

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[26] 105 FERC ¶ 61,297 (2003) (*OG&E*).

[27] DeRamus Affidavit at 27.

[28] *Id.* at 28.

[29] *Id.* at 32.

[30] *Id.* at 33.

[31] Occidental Protest at 13-15.

29. Occidental argues that Applicants' attempt to draw a parallel between the proposed transaction and other Commission-approved acquisitions of generation to serve native load is misleading. The proposed transaction is unique because it involves an asset in distress as a result of Entergy's exercise of market power. Occidental points to the caution provided by Calcasieu Power, along with other independent power producers (IPPs) and wholesale customers, that deficiencies in Entergy's transmission grid "have the effect of suppressing competition by...preventing IPPs from reaching customers within and outside the Entergy region, causing many of those IPPs to suffer competitive distress to the point at which they have no choice but to sell their assets to Entergy at fire-sale prices."[32]

30. Occidental discounts Applicants' contention that because Entergy does not have market-based rate authority in its home control area, it has no incentive to increase prices there. The Commission's merger review authority — and its obligation to ensure that a merger does not harm competition and is consistent with the public interest — applies to markets in which the merging parties do not have market-based rate authority as well as to markets in which they have such authority.[33] Applicants' conclusion appears to be based on an overly narrow definition of market power. Economists and antitrust courts have long recognized that a market participant is able to exercise market power if it is able either to increase prices above a competitive level or to exclude competition.[34] Occidental maintains that because Entergy's lack of market-based rate authority constrains its ability to raise prices, the primary way in which Entergy can exercise market power with respect to generation is through market foreclosure.[35]

31. Occidental challenges Applicants' contention that the proposed transaction does not create a market power problem because Calcasieu's capacity factor is so minimal. The Facility would account for 17 percent of Entergy's peaking capacity in its home control area and 51 percent of the total peaking capacity in the WOTAB load pocket.[36]

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[32] Occidental Protest at 15-16 (citing the Request for Rehearing of Arkansas Electric Cooperative Corp., *et al.* filed on April 21, 2005 in Docket No. EL05-52 at 31).

[33] DeRamus Affidavit at 40.

[34] *Id.* at 40 (citing *United States v. E. I. du Pont de Nemours & Co.*, 351 U.S. 377 (1965)).

[35] Occidental Protest at 16.

[36] *Id.* at 17-18.

32. Occidental says that the proposed transaction will result in the removal of an active competitor from the wholesale market. This alone means that the transaction raises wholesale market power issues. Any increase in market concentration (and Entergy's generation dominance) caused by the transaction will affect the competitiveness of the wholesale market.

33. Occidental argues that the proposed acquisition is contrary to the public interest because it increases the incentive and ability for Entergy to favor its generation interests over those of its competitors – especially qualifying facility (QF) competitors. Entergy rebuffed Occidental's efforts to obtain a long-term contract to sell power from the Taft QF in accordance with the Public Utility Regulatory Policies Act of 1978 (PURPA).[37] Instead, Entergy acquired the distressed Perryville facility. This is an example of Entergy resisting its obligation under the law to transact with a competitor until governmental orders require it to meet that obligation. Occidental cites Entergy's rejection of Occidental's bids for the Multiple-Year Unit Capacity Call Option because Occidental refused to waive its rights under PURPA. This is an example of Entergy circumventing the competitive procurement process to avoid buying power from competing generation.

34. Occidental argues that Applicants have not analyzed whether the purported benefits of increased system reliability and cost savings in peaking capacity resulting from the acquisition can be obtained through other means. The benefits Applicants attribute to the transaction are a consequence of the dispatch of the Facility, not of its acquisition by Entergy. If Entergy's ownership of the Facility is expected to change fundamentally the way in which the Facility is dispatched, that change provides significant evidence of anticompetitive foreclosure. Occidental argues that this indicates that the transaction would harm competition and be inconsistent with the public interest.[38]

35. Occidental requests that the Commission either reject the proposed acquisition or impose conditions on it. The Commission should condition any approval on the completion of additional transmission upgrades in Amite South and WOTAB. Occidental also requests that before approving the acquisition, the Commission hold a trial-type proceeding to determine the mitigation that is necessary to alleviate the anticompetitive effects of Entergy's acquisition of the Facility.

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[37] 16 U.S.C. § 824a-3 (2000).

[38] Occidental Protest at 30-31.

iii. Applicants' Answer

36. Applicants state that using the WOTAB region as the relevant geographic area is not appropriate, given current market conditions in the Entergy system control area. Citing Order No. 642, Applicants state that where there are no transmission constraints between markets and where there is a demonstrated lack of price discrimination, similar prices across destination markets generally indicate a larger, single geographic market.[39] Applicants claim that the historical publication of a single "Into Entergy" spot price, not differentiated within the Entergy system control area, demonstrates a lack of price discrimination within the control area, and it shows that the control area is thus a single market. The Entergy Operating Companies operate as one control area or balancing authority. Applicants state that the Commission has recognized that analysis of sub-markets makes sense only when transmission congestion is used to set the price for a product, as in the case of locational marginal pricing (LMP) of transmission congestion. Applicants note that LMP is not used in the Entergy system control area.[40] An alternative analysis of the WOTAB region would show results similar to those for the Entergy system control area.[41]

37. Applicants argue that they correctly calculated the amount of rival generation. Expansion of generation capacity from the date of the Phase II Transmission Study Report quoted by Occidental (February 9, 2004) to the present explains the difference between their respective figures. Applicants also claim that Occidental did not include generation from various municipalities and other traditional load-serving entities in their calculations, biasing Occidental's numbers downwards. Further, the difference in rival generating capacity claimed by Occidental is not material in Applicants' DPT analysis.[42] Likewise, Applicants claim that the difference Occidental finds in simultaneous import capability values is based on the outdated historical study Occidental used.[43]

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[39] Applicants' Answer at 5 (citing *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,891 (2000)).

[40] *Id.* at 5-6 (citing *Sithe Energies, Inc.,* 93 FERC ¶ 61,244 (2000).

[41] *Id.*, Exhibit J-10 (Arenchild Rebuttal) at 5. Applicants did not perform this analysis, however. Arenchild Rebuttal, at 20.

[42] *Id.* at 7.

[43] *Id.* at 8.

38. Applicants contend that the Equivalent Forced Outage Rate incorporated in their analysis is an industry standard commonly used in other DPT computations submitted to the Commission. They argue that if they had used the Forced Outage Rate, as suggested by Occidental, there would be little difference in the results of their DPT computations. As long as outage rates are applied consistently to all units in the analysis, any difference should be largely symmetrical.[44]

39. Applicants challenge Occidental's claim that Entergy has a 67 percent market share. Occidental incorrectly eliminated a significant number of transactions for other entities, but not for the Entergy Operating Companies and their affiliates. Applicants say that Entergy's market share of wholesale sales is less than 4 percent.[45]

40. Applicants argue that they provided adequate workpapers in support of their analysis. The workpapers offer the same kind of support as workpapers provided to the Commission in other section 203 proceedings. They claim that other necessary data is publicly available on their Open Access Same-Time Information System (OASIS).[46]

41. Applicants argue that a cumulative DPT analysis is not necessary. They contend that load growth, combined with the legal obligation to serve the growing energy needs of their native load electricity customers, requires Entergy to acquire capacity. Even with the acquisition of the Facility, the Entergy Operating Companies are still short of capacity to meet their forecasted requirements.[47]

42. Applicants state that the output of the Facility is currently sold to the Entergy Operating Companies under two long-term agreements. Entergy included these agreements in the Notice of Change of Status it submitted in Docket No. ER91-569 on June 20, 2006.[48] Because the Entergy Operating Companies reported control of the Facility through the long-term agreements, the actual purchase of the Facility has no effect on the HHI calculation. Applicants state that their conservative analysis ignored

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[44] *Id.* at 9.

[45] *Id.* at 10.

[46] *Id.* at 10-11.

[47] *Id.* at 11-12.

[48] *Id.* at 13, citing *Entergy Services, Inc.*, *et al.*, 116 FERC ¶ 61,276 (2006).

the existing agreements and assumed that the change due to the transaction is the full amount of the Facility's generating capacity in order to present the worst-case scenario.[49]

43. Applicants argue that the proposed transaction does not eliminate a competitor, as Entergy Gulf States is acquiring neither Calcasieu Power nor Dynegy Power Marketing, Inc., both of which remain free to participate in competitive wholesale power markets in the region.[50]

44. Applicants argue that the market power issues raised by Entergy Gulf States' acquisition of the Facility are quite specific and are not the traditional issues raised in horizontal acquisitions. The Entergy Operating Companies do not have market-based rates for power sales within their home control area and thus cannot exercise market power by raising prices. They argue that Occidental has not explained how the transaction would enable them to exercise market power in light of Entergy Operating Companies' cost-based rates. The Entergy Operating Companies are net buyers of power and thus have no incentive to raise prices in these markets. Applicants characterize the transaction as necessary to serve load, not an attempt to raise prices or foreclose rivals.[51]

45. Applicants claim that the variations in the capacity factor of the Facility between 2005 and 2006 do not indicate anything relevant to the proposed transaction.[52]

46. Applicants argue that the EC measure is not a valid measure of competition in markets, such as the Entergy system control area, where there is no retail access and no definitive plan for retail access in the foreseeable future. Applicants argue that, as in *Nevada Power* and *Westar Energy, Inc.*, AEC is the relevant measure of market power in this case.[53]

47. Applicants argue that the proposed transaction would have no effect on the Entergy Operating Companies' obligations under PURPA. Occidental will continue to receive avoided cost for all PURPA "puts." Applicants argue that the *Mountainview Power Company, LLC* case cited by Occidental indicates that PURPA issues are beyond

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[49] *Id.*

[50] *Id.* at 14.

[51] *Id.* at 16-17.

[52] *Id.* at 17.

[53] *Id.* at 18-19.

the scope of section 203 proceedings.[54] Arguments concerning QF discrimination are also beyond the scope of this proceeding.[55]

48. Applicants argue that an evidentiary hearing is not necessary.[56] In addition, requiring Entergy to complete upgrades in the Amite South region would not remedy any anticompetitive harm from the transaction.[57]

iv. Response to Staff Letter

49. The June 7, 2007 Staff Letter requested that Applicants provide an analysis of the effect of the transaction on competition in the WOTAB region. Applicants disagree with Occidental that the WOTAB region is the relevant geographic market but perform the Appendix A analysis requested by staff. They state that their results show that the Commission's safe-harbor thresholds for the AEC measure are easily met even when the relevant geographic market is assumed to be the WOTAB region and conservative assumptions are used. Applicants state that during the three periods relevant to their analysis, the market for AEC is not concentrated (as indicated by a post-transaction HHI below 1,000), so no further analysis is necessary. In addition, even if the market were moderately concentrated (HHI between 1,000 and 1,800), the transaction would still meet the Commission's safe-harbor thresholds.

50. Applicants' analysis for EC found screen failures (HHI changes between 322 and 342) in the highly concentrated (HHI > 1,800) WOTAB market. Applicants argue that these screen violations do not indicate any actual competitive concerns because the screen results are similar to those in the *Nevada Power Co.* case, where the Commission found no competitive concerns.[58]

51. Applicants stress that for the purposes of providing a conservative, worst-case analysis they intentionally ignored the fact that, at the time of their response, the output of the Facility was sold under contract to the Entergy Operating Companies under two long-term agreements, which were to be converted to a tolling agreement, effective on

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[54] 109 FERC ¶ 61,086 (2004).

[55] Applicants' Answer at 22-23.

[56] *Id.* at 24.

[57] *Id.* at 26.

[58] Response to Staff Letter at 6-7.

July 1, 2007. Applicants again point out that the Facility's output was included in the Notice of Change of Status submitted by the Entergy Operating Companies in Docket No. ER91-569 on June 20, 2006. Further, the Commission accepted the Notice of Change in Status by order dated September 22, 2006.[59] Applicants argue that because the Entergy Operating Companies previously reported control of the Facility through the long-term agreements, and will continue to retain control through the tolling agreements, the actual purchase of the Facility has no effect in the HHI calculation in the WOTAB region.[60]

v. **Supplemental Protest**

52. Occidental argues that Applicants' new DPT for the WOTAB region is based on several false assumptions. The most significant flaw is their *pro rata* allocation of the internal import limits into WOTAB among all suppliers with available economic capacity. Occidental argues that it is more appropriate to allocate those limits by assigning to Entergy's AEC outside of WOTAB a priority over other competing sources of generation located in other regions of the Entergy control area. Occidental argues that Commission precedent requires this.[61] In the case they cite, the applicants likewise attempted to use a *pro rata* allocation, assuming that other suppliers would have the same rights to the internal transmission interface capability as the applicants. The Commission, however, found that allocating to competing sellers unreserved transmission capability over interfaces internal to the merged company was not appropriate. The Commission found that transmission capability that is not under contract warrants a more conservative approach because utilities are permitted to reserve internal capability to serve their native load before suppliers have an opportunity to use it.[62]

53. Occidental's own analysis, which it claims properly allocates transmission imports, shows that the transaction causes HHI changes between 145 and 253 points in a moderately concentrated market (pre-transaction HHIs between 1000 and 1800) for the

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[59] *Id.* at 7 (citing *Entergy Services, Inc.*, 116 FERC ¶ 61,276 (2006)).

[60] *Id.*

[61] *Id.* at 4 (citing *Ohio Edison Co.*, 80 FERC ¶ 61,039 at 61,103 (1997)).

[62] *Id.* at 4-5.

Summer Super Peak 1 and 2 load periods. These results are well above the threshold of 100 points used by the Commission in moderately concentrated markets.[63]

54. Occidental argues that the Applicants continue to overestimate outage rates, with the result that their DPT analysis continues to understate the amount of AEC. Correct outage rates result in even more severe DPT failures for the Summer Super Peak 1and 2 load periods.[64]

55. Occidental argues that Applicants' new DPT analysis fails to account for the native load attributable to utilities other than Entergy. As an example, Applicants treat Central Louisiana Electric Cooperative's 50 percent ownership in Acadia Energy Center as being available for wholesale sales, but this ignores that entity's own native load commitments.[65] Occidental argues that the effect of these additional corrections increases the HHI changes attributable to the transaction.

56. Occidental continues to argue that EC screen failures indicate competitive harm. The market conditions in that case are quite different from those in *Nevada Power*. Occidental concludes that Applicants' reliance on this case as support for their claim that AEC is the more relevant measure is misplaced.[66]

57. Occidental next argues that Applicants' analysis fails to give adequate consideration to historical trade and transmission data. This data contradicts Applicants' assumption that competing sources of generation can participate in the wholesale market on terms similar to Entergy's generation.[67] Occidental argues that this data indicates that Applicants' DPT results underestimate Entergy's actual market share and also the overall level of market concentration for both WOTAB and the Entergy control area.[68]

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[63] *Id.* at 5.

[64] *Id.* at 5-6.

[65] *Id.* at 6.

[66] *Id.* at 8.

[67] *Id.* at 9. Occidental cites differences in capacity factors for various facilities owned and not owned by Entergy to support its point.

[68] *Id.* at 10.

58. Finally, Occidental continues to argue that Applicants' Appendix A analysis is incomplete.[69] Occidental contends that because there are genuine issues of material fact that cannot be resolved on the basis of the written record, the Commission should either reject the application or set for hearing what mitigation is needed to address the competitive harm caused by the transaction.[70] The Commission should institute a paper hearing with a limited period of discovery if it determines that holding a trial-type proceeding is not feasible due to the statutory deadlines applicable to section 203 applications.

vi. Answer to Supplemental Protest

59. Applicants argue that *Ohio Edison* is not controlling in this case. *Ohio Edison* dealt with a merger of two vertically-integrated utilities with separate control areas. The applicants in *Ohio Edison* proposed to combine their control areas and operate under a new, single-system open access transmission tariff following the merger and also to conduct joint-dispatch of the combined system. Applicants argue that the concern in *Ohio Edison* was whether the combined entity could reserve the transmission capacity following the merger that previously was an external path between the two control areas, but would become an internal path post-merger. In the present case, the proposed transaction does not involve merging separate control areas and does not result in a change in transmission access. Applicants thus argue that the concern presented in *Ohio Edison* does not exist here. Applicants further argue that while Occidental maintains that the Entergy Operating Companies should have a priority to the transfer capability over other sources of generation located outside of WOTAB, the argument is based on fallacious premises because the Entergy Operating Companies and their affiliates do not have any special or unique claim to use the transfer capability within the Entergy system control area to make sales in WOTAB over and above any native load requirements.[71]

60. Applicants argue that they accounted for the output of the Acadia Plant correctly. They say that Occidental fails to recognize that an unaffiliated third-party, Tenaska Power Services Company, has an energy management services agreement with respect to

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[69] *Id.*

[70] *Id.* at 12.

[71] Answer to Supplemental Protest at 5-6.

the Acadia Plant. Under this agreement, Tenaska Power controls the output of this plant.[72]

vii. Commission Determination

61. We find that the horizontal combination of generation resulting from the transaction will not adversely affect competition. We make this determination despite the discrepancies in the results of the various DPT analyses in this record, which we find are not controlling in this case. Even assuming, *arguendo*, that the analysis of the competitive effects in the WOTAB region does result in failures of the Competitive Analysis Screen, we find that Entergy's purchase of the Facility does not harm competition.

62. Appendix A of the Merger Policy Statement states that even if screen failures are present, the Commission will nevertheless take into account the competitive facts of the case.[73] The relevant competitive facts here are that the Facility is a peaking plant that has historically run for only approximately 50 hours per year. The record indicates that Entergy Gulf States is approximately 1,200 MWs short of its projected 2008 peak demand plus reserve requirement. Because Entergy is short during the periods when the Facility will be operational, and it needs this power supply to help maintain reliability, it will not have an incentive to attempt to exercise horizontal market power during these times by withholding the Facility from the market. Physical withholding of the Facility would require Entergy to purchase even more electric energy from elsewhere at a higher price, making a withholding strategy counterproductive. Thus, we find no adverse effect on competition as a result of this acquisition.

b. Vertical Market Power Issues

i. Applicants' Analysis

63. Applicants assert that the proposed transaction does not increase any ability they have to abuse their ownership of transmission facilities to give themselves an advantage in energy markets. They explain that the Entergy Operating Companies provide transmission service under an open access transmission tariff (OATT) and that the

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[72] *Id.* at 8.

[73] Merger Policy Statement at 30,135; *Commonwealth Edison Co.*, 91 FERC ¶ 61,036, at 61,133 & n.42 (2000); *Duke Energy Corp. and Cinergy Corp.*, 113 FERC ¶ 61,297, at P 83 (2005); Supplemental Policy Statement at P 60.

Commission recently approved the Entergy Operating Companies' request to contract with an independent entity, the Independent Coordinator of Transmission (ICT), to provide oversight over the operations of the Entergy Operating Companies' transmission system.[74] The Southwest Power Pool, Inc. is the ICT. They assert that with the transfer of Calcasieu Power's limited transmission facilities to Entergy Gulf States, Calcasieu Power will have no transmission facilities that it could use to exercise market power.

64. Applicants further state that section 33.4(a)(1) of the Commission's regulations requires a vertical analysis only if a transaction results in a single entity controlling both generation and inputs to generation. They assert that because no natural gas transportation assets or other inputs to gas-fired generation facilities are being transferred as part of the proposed transaction, no vertical market power issues are raised and no vertical analysis is required.

ii. <u>Protests</u>

65. Occidental argues that Entergy's acquisition of the Facility provides Entergy with an opportunity to use its control of its transmission network to disadvantage its competitors in the wholesale markets. This, in turn, disadvantages Entergy's retail customers by shielding system costs from the benefits of competition. As the Commission found in *OG&E*, the increase in vertical market power comes from the fact that Entergy, a vertically integrated utility, would be adding 310 MWs of generation capacity to its existing transmission and generation facilities, thus increasing its incentive to use its control of transmission facilities to disadvantage its competitors.[75] Occidental adds that Applicants' reliance on Entergy's OATT and the ICT is misplaced, as the Commission has never used a bright-line approach to vertical market power issues. The Commission has rejected arguments that the OATT mitigates increases in vertical market power because the OATT fails to address the opportunity for undue discrimination and the incentive for vertically integrated utilities to use their transmission facilities to harm competition.[76] Occidental argues that while the Commission recently adopted reforms to address the opportunities for discrimination under the OATT, there is no basis to conclude that these reforms will eliminate the opportunities for Entergy to engage in

[74] *Entergy Services, Inc.*, 115 FERC ¶ 61,095, *order on reh'g*, 116 FERC ¶ 61,275 (2006).

[75] Occidental Protest at 22.

[76] *Id.* at 26-27, citing *OG&E*.

discrimination.[77] Occidental states that the Commission has found Entergy to be violating its OATT, and Entergy has demonstrated that it does not abide by commitments made to regulators to remedy the Amite South constraint in the Gulf States Utilities Company merger and the Final Phase II Transmission Study Report.[78] Occidental concludes that the reformed OATT will not change Entergy's pattern of non-compliance.[79]

66. Occidental argues that the ICT also does not eliminate vertical market power concerns. The Commission has made clear that the only way the ICT could alleviate such concerns is if Entergy's transmission facilities were under the functional control of the ICT.[80] Occidental argues that the ICT will not be able to address vertical market power issues as long as its authority is limited to implementing criteria, standards, and policies developed by Entergy. The ICT cannot relieve transmission constraints by ordering Entergy to construct new facilities.

67. Occidental recommends that, if the Commission approves the transaction, we impose conditions to address its negative effects. The most immediately feasible mitigation is transmission expansion. The only way to address meaningfully the competitive threat of Entergy's increased generation market power is to require Entergy to remedy its major constrained load pockets (Amite South and WOTAB). Occidental argues that this is appropriate in Amite South, given that area's exceptionally high level of market concentration and large amount of system load, Entergy's continued delays in fulfilling its commitments to relieve transmission constraints and the system-wide benefits that will result from relieving them. In any event, the Commission should establish a trial-type proceeding to identify the mitigation that is necessary to alleviate the anticompetitive effects that will result from Entergy's acquisition of the Facility.[81]

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[77] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007).

[78] *Entergy Services., Inc.*, 65 FERC ¶ 61,332 at 62,480 (1993), *order on reh'g*, 67 FERC ¶ 61,192 at 61,584 (1994). See also Final Phase II Transmission Study Report, available at http://www.lpsc.org.

[79] Occidental Protest at 27.

[80] *Id.* at 27-28 (citing *Entergy Services, Inc.*, 115 FERC ¶ 61,095, P 116 (2006)).

[81] *Id.* at 31-32.

iii. Applicants' Answer

68. Applicants argue that the proposed transaction does not increase any ability Applicants could have to abuse their ownership of transmission facilities to give themselves an advantage in energy markets. Applicants argue that access to, and service on, Entergy Gulf States' transmission facilities under the Entergy Operating Companies' OATT addresses the vertical market power issue. Applicants state that the Commission has held that a commitment to join an ISO or an RTO mitigates any potential vertical market power.[82]

69. Applicants further argue that the ICT directly addresses many of the issues raised by Occidental in its protest. For example, the Commission has determined that the ICT has sufficient authority to grant or deny transmission service independently and fairly, to perform feasibility and system impact studies, to administer the Entergy Operating Companies' OASIS, and to ensure that the OATT is administered in a non-discriminatory fashion. The Commission has already rejected Occidental's argument that the ICT's authority is limited to implementing criteria, standards, and policies Entergy developed in the Available Flowgate Capacity proceeding.[83] Occidental's assertions thus are a collateral attack on the Commission's orders on the ICT.

70. Applicants further argue that Occidental's transmission concerns are unrelated to the proposed transaction.[84] Applicants point out that neither the Entergy Operating Companies nor their affiliates are acquiring any additional transmission assets, other than Calcasieu's limited interconnection facilities. Having direct ownership of a peaking facility, as opposed to controlling the same facility by contract, does not affect the Entergy Operating Companies' incentives to exercise vertical market power, if that were possible.[85] Applicants maintain that Occidental's assertions regarding market foreclosure, monopsony power and lack of transmission investment as a barrier to entry, as well as Occidental's argument that the benefits of the transaction could be obtained in other ways, also are unrelated to the transaction.[86]

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[82] Applicants' Answer at 20.

[83] *Id.* at 21 (citing *Entergy Services, Inc.*, 119 FERC ¶ 61,018 (2007)).

[84] *Id.* at 20-22.

[85] Arenchild Rebuttal at 9-10.

[86] *Id.* at 10.

iv. Commission Determination

71. We find that the proposed transaction does not increase any ability the Applicants have to abuse their ownership of transmission facilities to give themselves an advantage in energy markets because Entergy's transmission system is operated under a Commission-approved OATT, which ensures open access to the transmission system, and its operation is overseen by the ICT. We will not condition section 203 authorization on Entergy completing transmission upgrades in Amite South or WOTAB, as requested by Occidental, because the record does not indicate that the transaction will result in increased congestion in those areas. The Commission conditions section 203 authorizations only when needed to address specific, transaction-related harm.[87]

72. The acquisition of a peaking facility inside a load pocket might increase congestion only if Entergy Gulf States purchases this facility only to withhold it from the market, replacing its output with more costly energy from outside the WOTAB region. However Applicants state that the Facility will provide peaking and reserve capacity that can be scheduled within the current day for generation failures, unexpected demand, or to avoid purchases. In addition, as discussed above, Entergy will not have an economic incentive to withhold the output of the Facility.

2. Effect on Rates

a. Applicants' Analysis

73. Applicants assert that the proposed transaction will not have an adverse effect on transmission rates because no significant transmission system facilities are being transferred from Calcasieu Power to Entergy Gulf States. They state that the only transmission facilities being transferred are interconnection facilities, so Entergy Gulf States' transmission rates will be unaffected. Moreover, Calcasieu Power does not provide transmission service.

74. With respect to wholesale requirements rates, Applicants state that Entergy Gulf States is obligated to serve its wholesale requirements customers. They state that any future long-term wholesale requirements contracts in the Entergy system control area will be filed under section 205 of the FPA[88] as cost-based rates. Moreover, the rates in Entergy Gulf States' existing wholesale power supply contracts will not be modified as a

[87] *See, e.g., Duke Energy Corporation,* 113 FERC ¶ 61,297 at P 82 (2005).

[88] 16 U.S.C. § 824d (2000).

result of the proposed transaction. The transaction would not have any effect on Calcasieu Power's or Dynegy Power Marketing, Inc.'s wholesale rates, and neither Calcasieu Power nor its affiliate Dynegy Power Marketing, Inc. have any long-term commitments to sell power from the Facility that could be affected by the transaction, other than the two agreements discussed above. Finally, Applicants state that the Facility will be reflected in Entergy Gulf States' capability under the Entergy System Agreement, and accordingly, the costs of the Facility will flow through the various System Agreement service schedules.

b. Protests

75. The Arkansas Commission argues that Applicants have not shown that the transaction will not adversely affect rates. The Arkansas Commission argues that Applicants have provided no analysis of the relative effects of the proposed transaction on the different Entergy Operating Companies under their System Agreement, including "bandwith" payments under the System Agreement.[89] In Opinion Nos. 480 and 480-A,[90] the Commission adopted a bandwidth remedy to implement rough production cost equalization among the Entergy Operating Companies. The Arkansas Commission says that with the bandwidth remedy and the current production cost levels among the Entergy Operating Companies, any increase in production costs of Entergy Operating Companies other than Entergy Arkansas, Inc. (EAI) will automatically result in an increase in EAI's bandwidth payments.[91] The Arkansas Commission argues that Entergy's testimony before the Louisiana Commission indicates that the EAI may be harmed by the proposed transaction. Entergy estimates in that proceeding that the first year's cost of the plant will be approximately $16 million. The Arkansas Commission concludes that since EAI's load ratio is approximately 20 percent, the bandwidth remedy requires that EAI's bandwidth payments increase by approximately $3.2 million due to the transaction.[92]

76. The Arkansas Commission also questions whether the Facility should be considered a system generating resource. It argues that Entergy Operating Companies

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[89] Arkansas Commission Protest at 3.

[90] Opinion No. 480, 111 FERC ¶ 61,311 (2005); Opinion No. 480-A, 113 FERC ¶ 61,282 (2005).

[91] Arkansas Commission Protest at 4.

[92] *Id.* at 5-6.

other than Entergy Gulf States, Inc. will not benefit from the transaction because the Facility will rarely enter the Entergy energy exchange.[93] There thus is a material issue of fact as to the effect of the proposed acquisition on the Entergy Operating Companies' wholesale rates, and an evidentiary hearing into the matter is necessary.[94]

c. Applicants' Answer

77. Applicants argue that the transaction will not have any adverse effect on the rates paid by Entergy Gulf States' wholesale power customers or the Entergy Operating Companies' transmission customers. Applicants assert that the Calcasieu transaction is the least costly option of the viable alternatives available to get the power they need. Furthermore, the transaction will have a minimal effect on the relative rates of the Entergy Operating Companies.[95] The Facility will be an Entergy system resource and will provide benefits to all of the Entergy System Agreement participants. The acquisition will not adversely affect rates compared to other options.[96]

78. Applicants criticize the Arkansas Commission's argument that the Facility should not be considered as an Entergy system resource. They point to other generation facilities that are considered to be Entergy system resources but whose output rarely passes through the Entergy energy exchange.[97]

79. Applicants state that the transaction will increase the total Entergy system capacity by approximately 1.5 percent and increase the total annual Entergy system revenue requirement by a smaller amount. Applicants contend that the transaction will have a minimal effect on the relative rates of the Entergy Operating Companies.[98]

80. Applicants recognize that Opinion Nos. 480 and 480-A can result in one Entergy Operating Company's resource planning decisions affecting other Entergy Operating

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[93] *Id.* at 5.

[94] *Id.*

[95] Applicants' Answer at 3.

[96] *Id.* at 27.

[97] *Id.* at 29-30.

[98] *Id.* at 31.

Companies. However this cannot prevent an Entergy Operating Company from acquiring resources. Applicants argue that whether an acquisition increases or decreases an individual Entergy Operating Company's costs should not be a condition for qualifying a unit as an Entergy system resource, given the need for additional capacity. The showing that the Entergy system needs the capacity that the Facility will provide, combined with the fact that the acquisition is less costly than other alternatives, overcomes the Arkansas Commission's objections.

d. <u>Response to Staff Letter</u>

81. Applicants state that Entergy Gulf States serves four wholesale requirements customers, who all have fixed, cost-based rate agreements and who do not oppose the transaction. Applicants submit that the Arkansas Commission has not shown that any wholesale requirements customers or transmission customers are likely to be harmed as a result of the transaction. Thus no additional ratepayer protection is necessary.[99]

82. Applicants note that the Arkansas Commission appears to be concerned about the effect of the transaction on the Entergy System Agreement. The Arkansas Commission's protest mainly relates to the costs of the Facility in the calculation of production costs under Opinion Nos. 480 and 480-A. Applicants argue that this issue is outside the scope of this proceeding and is already before the Commission in another docket.[100]

e. <u>Commission Determination</u>

83. Applicants have shown that the proposed transaction is unlikely to affect wholesale rates. We note that that Entergy Gulf States' wholesale requirements customers all have fixed, cost-based rate agreements and have not argued that the transaction will not adversely affect their rates. Further, the transaction will have no effect on transmission rates because Calcasieu Power does not provide transmission service and no significant transmission system facilities are being transferred from Calcasieu Power to Entergy Gulf States as a result of the transaction. The issues raised

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[99] Response to Staff Letter at 9-10.

[100] *See Entergy Services, Inc.*, 120 FERC ¶ 61,020 (2007). In that order, the Commission refused to find that, where a resource to be acquired or constructed by one or more of the Entergy Operating Companies has met certain approval requirements, including a public interest finding by retail regulators that have jurisdiction, that resource will be a system resource, and all its costs may be reflected in the formula rates in the Entergy System Agreement.

by the Arkansas Commission are not properly a part of this proceeding. Opinion Nos. 480 and 480-A require Entergy to make annual filings that will be examined to ensure appropriate production cost equalization for the Entergy system. Concerns of the type expressed by the Arkansas Commission can be raised in connection with those filings.

3. Effect on Regulation

a. Applicants' Analysis

84. Applicants state that Entergy Gulf States' status as a FPA jurisdictional utility will not change as a result of the proposed transaction. State regulation will not be affected as a result of the proposed transaction, the Purchase Agreement requires that Entergy Gulf States obtain the approval of the Louisiana Commission, and Entergy Gulf States submitted its application for such approval on March 15, 2007.

b. Commission Determination

85. Applicants have shown that the proposed transaction will have no adverse effect on federal or state regulation. The Commission's review of a merger's effect on regulation is focused on ensuring that a merger does not result in a regulatory gap at the federal or state level.[101] The transaction will not create a regulatory gap at the federal level because the Commission will retain its regulatory authority over the merged companies. The Commission stated in the Merger Policy Statement that it ordinarily will not set the issue of the effect of a merger on state regulatory authority for a trial-type hearing where a state has authority to act on a merger. However, if the state lacks this authority and raises concerns about the effect on regulation, the Commission stated that it may set the issue for hearing and that it will address such circumstances on a case-by-case basis.[102] In this case, state regulation will not decrease as a result of the proposed transaction, and hence the effectiveness of state regulation will not be impaired. Entergy Gulf States submitted the Purchase Agreement to the Louisiana Commission for approval, as required. We note that no party alleges that regulation would be impaired by the proposed transaction, and no state commission has requested that the Commission address the issue of the effect on state regulation.

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[101] *Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044 at 30,124.

[102] *Id.* at 30,125.

4. Cross-Subsidization

a. Applicants' Analysis

86. Applicants argue that the transaction does not raise any concerns regarding cross-subsidization. Applicants attest that other than the transfer of the Facility to Entergy Gulf States from Calcasieu Power, which is not an associate company of Entergy Gulf States, the transaction does not call for any transfers of any facilities, much less any transfers between a traditional utility company and an associate company, either at the time of the transaction or the future. Applicants state that no new securities will be issued by Entergy Gulf States for the benefit of an associated company, either at the time of the transaction or in the future. Applicants state that Entergy Gulf States will not enter into any new pledges or encumbrances for the benefit of an associate company in connection with the transaction, either at the time of the transaction or in the future. Applicants submit that Entergy Gulf States intends to sell a portion of the output of the Facility to one of the Entergy Operating Companies under Service Schedule MSS-4 of the System Agreement. Service Schedule MSS-4 contains a formula rate for a unit power sale or purchased power sale among the Entergy Operating Companies. Applicants state that no other contracts between Entergy Gulf States and its affiliates are contemplated in connection with the transaction either at the time of the transaction or in the future.

b. Commission Determination

87. Applicants have demonstrated that the proposed transaction does not raise any concerns with respect to cross-subsidization. Consistent with Order No. 669,[103] Applicants have verified that the proposed transactions do not result in, at the time of this transaction or in the future: (1) transfers of facilities between a traditional utility associate company with wholesale or retail customers served under cost-based regulation and an associate company; (2) new issuances of securities by a traditional utility associate companies with wholesale or retail customers served under cost-based regulation for the benefit of an associate company; (3) new pledges or encumbrances of assets of a traditional utility associate company with wholesale or retail customers served under cost-based regulation for the benefit of an associate company; or (4) new affiliate contracts between non-utility associate companies and traditional utility associate companies with wholesale or retail customers served under cost-based regulation, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.

[103] Order No. 669, FERC Stats. & Regs. ¶ 31,200 at P 169.

5. Analysis of Proposed Accounting

88. The application includes a proposed accounting entry recording Entergy Gulf State's acquisition of the Facility.[104] Entergy Gulf States proposes to debit Account 102, Electric Plant Purchased or Sold, and credit Account 232, Accounts Payable, in the amount of $56,500,000, the estimated purchase price of the Facility. However, Entergy Gulf States does not provide a journal entry clearing the original cost, related accumulated depreciation, and any acquisition adjustments from Account 102.

89. Electric Plant Instruction No. 5 of the Commission's Uniform System of Accounts requires that the purchase of electric plant that is an operating unit or system must be cleared through Account 102. Accordingly, Entergy Gulf States must debit the original cost, estimated if not known, to Account 101, Electric Plant in Service, with a concurrent credit to Account 102 and credit accumulated depreciation and amortization applicable to the original cost of the Facility to Accounts 108, Accumulated Provision for Depreciation of Electric Utility Plant, and 111, Accumulated Provision for Amortization of Electric Utility Plant, with a concurrent debit to Account 102. Any amounts remaining in Account 102 must be closed to Account 114, Electric Plant Acquisition Adjustments.

The Commission orders:

(A) The proposed disposition of jurisdictional facilities is hereby authorized as discussed in the body of this order.

(B) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever now pending or which may come before this Commission.

(C) The Commission retains the authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(D) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

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[104] On February 23, 2000, in Docket No. ER00-1049-000, the Commission waived its accounting and reporting requirements at 18 C.F.R. Parts 41, 101, and 141 for Calcasieu Power. *Lake Wentworth Generation, LLC, et al.*, 90 FERC ¶ 61,164 (2000). Therefore, Calcasieu Power did not provide accounting entries for the sale of the Calcasieu Facility to Entergy Gulf States.

(E) Applicants shall make appropriate filings under section 205 of the FPA, as necessary, to implement the acquisition and disposition.

(F) Applicants shall notify the Commission within 10 days of the date that the acquisition and disposition of jurisdictional facilities have been consummated.

(G) Applicants must inform the Commission of any change in circumstances that would reflect a departure from the facts the Commission relied upon in authorizing the transaction.

(H) Entergy Gulf States shall account for the transaction in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold, of the Uniform System of Accounts. Entergy Gulf States shall submit its final accounting entries within six months of the date that the transfer is consummated, and the accounting submissions shall provide all the accounting entries and amounts related to the transfer along with narrative explanations describing the basis for the entries.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

113 FERC P 61297 (F.E.R.C.), 2005 WL 3477003

FEDERAL ENERGY REGULATORY COMMISSION
*1 Commission Opinions, Orders and Notices

Before Commissioners: Joseph T. Kelliher, Chairman; Nora Mead Brownell, and Suedeen G. Kelly.

Duke Energy Corporation Cinergy Corp.

Docket No. EC05-103-000
ORDER AUTHORIZING MERGER
(Issued December 20, 2005)

1. On July 12, 2005, as amended on August 4 and 10, 2005, Duke Energy Corporation (Duke) and Cinergy Corp. (Cinergy) (collectively Applicants) filed an application under section 203 of the Federal Power Act (FPA)[1] requesting Commission approval of their proposed merger, which includes: (1) the merger of Duke and Cinergy; and (2) the internal restructuring and consolidation of the merged company. The Commission has reviewed the merger under the Merger Policy Statement[2] and will authorize it as consistent with the public interest, as discussed below.

I. Background

A. Description of the Applicants

1. Duke

2. Duke's operations are conducted through a number of separate business units, which are described below. Duke Power is a division of Duke that operates Duke's franchised electric utility business unit. It is a vertically-integrated utility that generates, transmits, distributes and sells electricity, and has a franchised service territory in central and western North Carolina and western South Carolina. Duke Power owns over 18,000 megawatts (MW) of electricity and sells wholesale electric power to incorporated municipalities, electric cooperatives, and public and private utilities. It provides transmission service under an open access transmission tariff (OATT).

3. Duke Energy North American (DENA) is a separate business unit of Duke that manages power plants outside of Duke's franchised service territory and markets electric power and natural gas. DENA conducts business through its wholly-owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. and through Duke Energy Trading and Marketing, LLC (Duke Trading), a joint venture 40 percent owned by ExxonMobil Corporation. Through its affiliates and subsidiaries, DENA currently owns or operates approximately 10,000 MW of operating generation and makes wholesale sales pursuant to market-based rate authority.

4. Duke's Natural Gas Transmission business unit provides transportation and storage of natural gas for customers in the eastern United States and in Canada and is conducted primarily through Duke Energy Gas Transmission (Duke Gas Transmission), which owns Texas Eastern Transmission, LP (Texas Eastern), an interstate natural gas pipeline company that operates in the region.

5. Duke's Field Services business unit performs a number of functions related to the gathering and processing of natural gas and natural gas liquids and is conducted primarily through Duke Energy Field Services (Duke Field Services), a joint venture 50 percent owned by ConocoPhillips.

2. Cinergy

6. Cinergy is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA 1935).[3] It was created as a result of a merger of The Cincinnati Gas & Electric Company (CG&E) and the parent company of PSI Energy,

Inc. (PSI). CG&E and PSI collectively own over 12,000 MW of generation.

*2 7. CG&E is a combination electric and gas public utility and an exempt holding company under PUHCA 1935. It has a franchised service territory in southwestern Ohio and, through its principal subsidiary The Union Light, Heat and Power Company (Union Light), in northern Kentucky. CG&E and Union Light generate, transmit, distribute and sell electricity, distribute and sell natural gas, and provide natural gas transportation service for a limited amount of Cinergy-owned generation. CG&E also owns the KO Transmission Company (KO Gas Transmission), an interstate natural gas pipeline that extends from interconnections in Kentucky with Columbia Gulf Transmission Company and Tennessee Gas Pipeline Company to the city gates of CG&E and Union Light.

8. PSI is a vertically integrated, regulated electric utility that has a franchised service territory across north central, central, and southern Indiana.

9. Cinergy Services, Inc. (Cinergy Services) is a service company that provides Cinergy's subsidiaries with a variety of administrative, management, and support services.

10. Cinergy Investments, Inc. (Cinergy Investments) holds part of Cinergy's non-regulated, energy-related businesses and investments. These include Cinergy's wholesale natural gas marketing and trading operations, which are primarily conducted through Cinergy Market and Trading, LP, and Cinergy's cogeneration business, which is primarily conducted through Cinergy Solutions Holding Company. Cinergy Investments also holds approximately 900 MW of merchant generation in the Tennessee Valley Authority's (TVA) control area in Mississippi and Tennessee.

B. Description of the Merger

11. The proposed merger will create an entity with retail electric and gas customers in Ohio, Kentucky, Indiana, North Carolina, South Carolina, and Canada, and that will own over 45,000 MW of electric generation and 17,500 miles of natural gas transmission pipeline.

12. Duke has formed Duke Energy Holding Corp. (Duke Holding), which in turn formed two wholly-owned subsidiaries, Deer Acquisition Corp. and Cougar Acquisition Corp., which, as part of the proposed merger, will merge with and into Duke and Cinergy, respectively, with Duke and Cinergy as the surviving corporations and becoming wholly-owned subsidiaries of Duke Holding. After the consummation of these two mergers, Duke Holding will be renamed Duke Energy Corporation and will become a registered holding company under PUHCA 1935. The old Duke will be renamed Duke Power Company, LLC.

13. The proposed merger also contemplates a number of restructurings and transfers inside the new holding company. Among these steps, DENA's ownership of generation facilities in the Midwest (the DENA Midwest Assets), which are owned and operated by DENA subsidiaries, will be transferred to CG&E and operated together with CG&E's generation fleet. This transfer of the DENA Midwest Assets may be accomplished either through the transfer to CG&E of a DENA subsidiary's assets or through the transfer of a DENA subsidiary itself, and Applicants request Commission authorization for either means of transfer.

II. Notice and Responsive Pleadings

*3 14. Notice of Applicants' filing on July 22, 2005 was published in the *Federal Register*, 70 Fed. Reg. 42,044 (2005), with interventions and protests due on or before September 26, 2005. On August 25, 2005, Applicants submitted a motion for extension of time to submit comments until September 26, 2005. The Commission granted this motion in a notice issued on August 30, 2005. On December 14, 2005, Applicants filed a definitive agreement they have reached with TVA that provides for the expansion of the interface between the Duke Power control area and the TVA control area.

15. Motions to intervene or notices of intervention were filed by American Electric Power, Blue Ridge Power Agency, Carolina Utility Customers Association, FirstEnergy Service Company, Constellation Energy Commodities Group, Inc., Constellation Generation Group, LLC, Constellation NewEnergy, Inc., Indiana Industrial Consumers Group, Indiana Municipal Power Agency, North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency Number 1 and Piedmont Municipal Power Agency, North Carolina Utilities Commission, Northern Indiana Public Service

Company, Proliance Energy, LLC, Public Service Commission of the Commonwealth of Kentucky, South Carolina Electric & Gas Company, South Carolina Energy Users Committee, Steel Dynamics, Inc., Tennessee Valley Authority, Wabash Valley Power Association, Inc., Wisconsin Electric Power Company.

16. Motions to intervene and comments were filed by the Dayton Power and Light Company (Dayton). The Public Staff - North Carolina Utilities Commission and the Attorney General of the State of North Carolina (North Carolina Parties) filed a motion to intervene and comments.

17. Motions to intervene and protests were filed by Albert E. Lane, American Municipal Power-Ohio (AMP-Ohio), American Public Power Association and National Rural Electric Cooperative Association (APPA/NRECA), Office of the Ohio Consumers' Counsel (Ohio Consumers' Counsel), Public Citizen's Energy Program (along with Citizens Action Coalition of Indiana, Ohio Partners for Affordable Energy, and the Southern Alliance for Clean Energy) (collectively, Public Citizen), and South Carolina Public Service Authority (Santee Cooper). Hoosier Energy Rural Electric Cooperative filed a protest and request for hearing, which it subsequently withdrew. The Indiana Utility Regulatory Commission (Indiana Commission) filed a notice of intervention, protest, and suggestion to institute settlement process.

18. On July 28, 2005, Santee Cooper filed a motion to compel Applicants to supplement their filing. On August 4, 2005, Applicants filed a response to Santee Cooper's motion.

19. On October 11, 2005, Applicants filed an answer. On October 26, 2005, Santee Cooper filed an answer to Applicants' answer. On November 4, 2005, Applicants filed an answer to Santee Cooper's answer. On November 21, 2005, Santee Cooper filed an answer to Applicants' answer.

III. Discussion

A. Procedural Matters

***4** 20. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2005), the notices of intervention and timely, unopposed interventions and motions to intervene serve to make the entities that filed them parties to this proceeding.

21. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2005), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We will accept the answers and answers to answers submitted by Applicants and Santee Cooper because they have provided information that assisted us in our decision-making process.

B. Standard of Review under Section 203

22. Section 203(a) provides that the Commission must approve a merger if it finds that the consolidation "will be consistent with the public interest."[4] The Commission's analysis under the Merger Policy Statement of whether a consolidation is consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.

1. Effect on Competition

A. Horizontal Competitive Issues

i. Applicants' Analysis

23. The Applicants retained Dr. William Hieronymus to analyze the effect of the merger on competition. Dr. Hieronymus identifies three relevant products: non-firm energy, capacity, and ancillary services, across the geographic markets affected by the merger. He concludes that, as mitigated, the merger will not harm competition.

24. As required by the Commission's merger regulations, Applicants present an Appendix A analysis performed by Dr.

Hieronymus. Dr. Hieronymus analyzed markets in the footprint of the Midwest Independent Transmission System Operator (MISO), the PJM Interconnection (PJM), and the Duke Power control area. He identified three relevant geographic markets within MISO and PJM: MISO, the "MISO Submarket," and "MISO-PJM Midwest."[5] In his analysis of non-firm energy markets, Dr. Hieronymus uses Economic Capacity and Available Economic Capacity (Available Economic Capacity), as defined in the Merger Policy Statement, as proxies to represent a supplier's ability to participate in the market.[6] He uses the Delivered Price Test to evaluate the effect on competition in the relevant markets over 10 separate time periods: Super Peak, Peak and Off-Peak periods for Summer, Winter and Shoulder seasons, along with an extreme Summer Super Peak. He considers actual energy market and fuel prices during 2004, and forecast fuel prices for 2006, the test year for his analysis.[7]

a. <u>MISO and PJM Markets</u>

25. In his analysis of these markets, Dr. Hieronymus uses simultaneous import limits for imports into each geographic market that are based on a transmission study provided by Cinergy. The simultaneous import limits in his analysis are 15,766 MWs for MISO; 11,032 MWs for the MISO Submarket; and 9,705 MWs for the MISO-PJM Midwest market. For imports from PJM to MISO, Dr. Hieronymus used PJM's Open Access Same-time Information System (OASIS) postings of PJM's total transfer capability (TTC) to the former MISO control areas. Dr. Hieronymus allocates scarce transmission availability on a *pro rata* basis.

***5** 26. With respect to PUHCA 1935's integration requirements,[8] Dr. Hieronymus assumed 250 MWs of firm transmission from the Duke Power control area. He states that this 250 MWs of firm transmission is in addition to Duke's share of imports calculated in accordance with the Appendix A requirements. Dr. Hieronymus conducted two sensitivity analyses; the first assumes the use of a 100 MW path from Duke Power to Cinergy,[9] and the second assumes that there is no firm transmission integration path. In performing his analyses for the MISO and PJM markets, Dr. Hieronymus uses a range of prices from $30 per megawatt hour (MWh) in the Summer Off-Peak to $250 per MWh in the extreme Summer Super Peak. In addition, he conducted sensitivity analyses using slightly lower and higher prices.

27. For Economic Capacity, Dr. Hieronymus' results show that all the post-merger markets are unconcentrated in all time periods in each of the MISO, MISO Submarket, and MISO-PJM Midwest markets. According to Dr. Hieronymous, Herfindahl- Hirschman Index (HHI)[10] changes are under 50 in all time periods in each market: MISO (HHI change not more than 14), MISO Submarket (HHI change not more than 25), and MISO-PJM Midwest Market (HHI change not more than 37). Dr. Hieronymus states that under the Commission's Merger Policy Statement,[11] such a result satisfies the Appendix A screen analysis.

28. Applicants state that under the Available Economic Capacity measure, all three markets are unconcentrated both before and after the proposed merger. HHI changes are no more than 39 points in MISO, no more than about 50 points in MISO Submarket, and no more than about 60 points in MISO-PJM Midwest. As a result, Applicants state, the proposed merger passes the Available Economic Capacity test in all three relevant geographic markets analyzed.

b. <u>Duke Power Control Area</u>

29. Applicants state that because Duke Power is not a member of a regional transmission organization (RTO), Dr. Hieronymus analyzed the Duke Power control area as a separate destination market. As required by the Commission's merger regulations[12] in those circumstances, Dr. Hieronymus also analyzed all of Duke Power's first-tier control areas.

30. Applicants state that, with respect to import limits, Dr. Hieronymus used OASIS postings of the various entities involved, consistent with the Commission's Merger Policy Statement. He also used simultaneous import limits calculated by Duke Power in its market-based rate compliance filing as well as those in studies submitted by other market participants in their compliance filings.

31. Dr. Hieronymus adjusted his analysis of the 250 MW firm transmission path from the way it was modeled for the MISO and PJM markets in two respects. First, because the proposed path confers firm transmission rights only from Duke Power to Cinergy, Dr. Hieronymus used the "squeeze-down" method[13] for allocating import capacity into the Duke Power control area. Second, he assumed that no capacity is being delivered from Duke Power over the path into Cinergy. He also conducted a sensitivity analysis using a 250 MW firm path from Cinergy to Duke Power.

*6 32. For Economic Capacity, Dr. Hieronymus' results show that the HHIs in the Duke Power control area are above 1,800 both before and after the proposed merger; thus, the market is deemed to be highly concentrated. He finds that since the HHI changes are well below 50, however, the proposed merger does not cause any screen failures.

33. Applicants state that under the Available Economic Capacity measure, the Duke Power control area is either moderately or highly concentrated (with one time period unconcentrated), depending on the load conditions. Dr. Hieronymus states that the relevant HHI changes are below 50 points in all but one instance, when 39 MWs of Cinergy supply results in an HHI change of 65 points in a highly concentrated market.[14]

34. Dr. Hieronymus concludes that there is no systematic pattern of large HHI changes in the relevant market, and thus no concerns are raised. Applicants state that in the first-tier markets to the Duke Power control area, the competitive screen analysis is passed readily, with most markets unconcentrated in most time periods. Dr. Hieronymus' sensitivity analysis shows that mitigation approximately equal to the size of the firm path would be required if the Applicants obtain a firm path from Cinergy to Duke Power.

ii. Protests

35. Public Citizen raises objections to the Commission's approach to merger analysis generally. For instance, it claims that the Commission over-relies on industry analysis. Public Citizen opines that the public interest is not served by having one consulting firm, and one individual in particular, (Dr. Hieronymus of Charles River Associates) conduct every major merger analysis. Public Citizen argues that evidentiary hearings are required to determine whether the analysis provided by Dr. Hieronymus is prejudiced in favor of the companies that pay his salary.[15]

36. Public Citizen also states that the HHI is far too simplistic an index to measure market power in an industry as complex as the electric industry. It instead suggests that the Commission: use simulation modeling that directly measures market power, with a Price-Cost Margin Index; calculate the effects of generators' and power marketers' strategic behaviors to exercise market power; and include additional variables in its analysis.[16]

37. Public Citizen notes that Applicants did not include power marketers in their market power analysis. Public Citizen protests the entire market concentration analysis because it ignores the market concentration (and market power) effects of the Duke-Cinergy power marketing business, and requests that a new market power analysis be performed that includes all power marketing activities.[17]

38. AMP-Ohio states that the proposed merger could adversely affect competitive conditions in the regions in which the merged company will operate. It claims that the approach in the Commission's Merger Policy Statement is too limited to evaluate the broader effects of a merger on industry structure and market functionality.[18] It identifies increased opportunities for strategic bidding and economic withholding as the competitive harms that may result from the proposed merger. Specifically, AMP-Ohio claims that with generating assets both within the heart of MISO and at one of the major entry points to the proposed MISO-PJM joint energy market, Duke will have a host of opportunities to affect regional prices through the manner in which it dispatches the individual units comprising its diverse and far-reaching portfolio.[19] AMP-Ohio proposes that in order to ameliorate the competitive effects of the proposed merger, the proposed merger should be conditioned on a requirement that the merged company offer to sell ownership interests in the Cinergy transmission system to load-serving entities (LSEs), under reasonable terms and conditions.[20]

*7 39. APPA/NRECA state that the repeal of PUHCA 1935 implies that the Commission may need to reexamine its current method, the Appendix A analysis, of analyzing the impact of a merger on horizontal competition. APPA/NRECA argue that with the repeal of PUHCA 1935 the Commission is likely to be faced with several new "long-distance" mergers that may each pass the current Appendix A screen, but may nevertheless cumulatively undermine competition. Each time such a merger is approved, a competitor in the broader markets is eliminated, and the economic and political market power of the remaining competitors is strengthened.[21] North Carolina Parties agree and urge the Commission to be vigilant in assessing the potential of mergers and acquisitions of jurisdictional entities to undermine existing or potential competition.

40. Santee Cooper raises a related point, claiming that the Commission and the courts have been clear that, in determining

whether a merger is consistent with the public interest, the Commission has an obligation to consider relevant antitrust law and precedent.[22] The "potential competition" doctrine, which states that a merger may be unlawful if: the target market is substantially concentrated; the acquiring firm has the characteristics, capabilities and economic incentive to render it a perceived potential *de novo* entrant; and the acquiring firm's pre-merger presence on the fringe of the target market (as a potential entrant) in fact tempered oligopolistic behavior on the part of existing participants in the market.[23] Santee Cooper claims that, because of Duke's overwhelmingly dominant position in Southeastern markets, and in view of the ongoing and anticipated trend toward concentration in the electric generation market, Cinergy's elimination as a potential competitor in the markets in which Duke is dominant strongly suggests that the proposed merger runs afoul of the law.[24] Santee Cooper further submits that the Commission's principal concern when evaluating the proposed merger must be the substantial probability that the combining companies will emerge as a dominant supplier in an increasingly oligopolistic setting.[25]

41. Santee Cooper argues that Applicants' horizontal competition analysis is based on flawed assumptions and thus understates the potential for market power of the combined entity in the Duke Power control area. Santee Cooper's expert, Dr. John R. Morris, argues that Applicants' Appendix A analysis suffers from several factual errors. Specifically, Dr. Morris claims that Applicants ought to have incorporated the Midwest as a single, first-tier market in their analysis because the Commission has taken steps to ensure that MISO and PJM act as a single market. Santee Cooper cites the high correlation between real-time pricing in MISO and PJM. They also point to Applicants' representation of import capability into the MISO-PJM Midwest market, which shows the Duke Power control area as a first-tier market of MISO-PJM Midwest.[26] Santee Cooper argues that Dr. Hieronymus should have adjusted TTC seasonally, instead of using a single (May 2006) value to represent the entire year. Applicants' witness Dr. Morris notes that TTC data can vary significantly by season and that the monthly TTC data was available to Dr. Hieronymus.[27] Santee Cooper further argues that Applicants skew the results of their competitive analysis by using only the TTC data supplied by Duke. It is standard industry practice to use minimum reported TTC values when calculating import capability, which Applicants failed to do for the Duke-Southern Company interface.[28] Finally, Santee Cooper argues that Applicants understated the Cinergy pro rata share of import capability into the Duke Power control area by assigning portions of the pro rata share to generation that, due to remoteness, constraints and loop flows, it is unreasonable to factor in.[29]

***8** 42. Santee Cooper's witness Dr. Morris submits his own analysis. Santee Cooper states that Dr. Morris' corrections reveal violations of the horizontal competitive analysis under various screens: Economic Capacity, Available Economic Capacity, summer, winter, off-peak, Peak, and Super-Peak. Consequently, Santee Cooper claims that the proposed merger will harm competition in the Duke Power control area.[30]

43. Santee Cooper states that a firm transmission path from Cinergy to Duke will greatly exacerbate the screen violations in the Duke Power control area.[31] Santee Cooper's witness Dr. Morris argues that Applicants may have an incentive to pre-empt imports to maintain the market power that the Commission has already determined that Duke has. By acquiring a contract path, Applicants might more effectively integrate the two utility systems and reduce generation costs. Dr. Morris' analysis shows that integration of Applicants' systems could have saved $41,187 per MW in 2003 and 2004 by allowing them to transmit electricity from Cinergy to Duke, translating into $4.1 million in savings for a firm contract path of 100 MWs and $10.3 million for a 250 MW path. Santee Cooper argues that if the Commission approves the proposed merger and Applicants maintain their generation assets in the Carolinas, PJM, and MISO, the Commission would need to rigorously police Applicants' purchases of transmission, given their incentives to do so.[32] Finally, Santee Cooper argues that the Applicants' securing of non-firm transmission from Cinergy to Duke will crowd out other imports into the Carolinas and thus increase Applicants' market power in the Duke Power control area.[33]

iii. Applicants' Answer

44. Applicants challenge Public Citizen's arguments regarding market power, stating that Public Citizen failed to identify any reason for the Commission to conclude that the merger will have an adverse impact on competition.

45. In response to AMP-Ohio's assertion that the merger will create an opportunity for strategic dispatch that could affect prices, and possibly the availability of transmission capacity in the MISO market, Applicants state that AMP-Ohio provides no details in support of its theory. Applicants maintain that AMP-Ohio's claims consist of just the type of unsupported, general claims of harm that Merger Policy Statement says are insufficient grounds to warrant further investigation of an otherwise comprehensive analysis developed by the applicants.[34] Applicants further cite the Commission's statement in

Exelon Corporation and Public Service Enterprise Corporation[35] that there is no need for applicants to conduct a separate analysis of strategic bidding.

46. Applicants answer APPA/NRECA's and Santee Cooper's assertions regarding competitive harm associated with cross-country mergers by stating that these claims do not require the Commission to deviate from the Merger Policy Statement, absent identification of any potential harm to the public interest as a result of the merger. Applicants contend that these claims lack any indication of exactly how the Applicants could use their increased political power in a fashion that would injure competition. Because they do not own significant amounts of generation in the same market, their merger will not increase their market power in any market. The Commission's traditional Appendix A analysis continues to be an appropriate, conservative screen for determining when a market participant's acquisition of generation capacity will increase its market power in a relevant geographic market.[36] Applicants further maintain that competitive markets can only be assisted when the participants in those markets are economically strong, sustainable entities.

***9** 47. In response to Santee Cooper's critique of their horizontal competition analysis, Applicants note that Santee Cooper does not dispute the conclusion of Applicants' witness, Dr. Hieronymus, that there is no adverse competitive impact on Santee Cooper. Applicants assert that the proposed merger has no material impact on competition in Santee Cooper's control area. Further, no other entity, and in particular, no entity located in the Duke Power control area, where Santee Cooper asserts the competitive problems will occur, objects to the proposed merger.

48. Applicants answer Santee Cooper's assertion that the merger will harm competition in general by eliminating a prospective competitor in Duke's markets. They state that Cinergy has made only minimal sales of power in the Duke Power control area in the last two years. Applicants therefore argue that the proposed merger would not eliminate Cinergy as a competitor in the Duke Power control area market because Cinergy does not compete to make sales in that market.[37]

49. Applicants respond to Santee Cooper's critique of their horizontal competition analysis by claiming that in order to show horizontal screen failures, Santee Cooper adjusted Dr. Hieronymus' import assumptions in two respects that deviate from the Commission's Appendix A requirements.[38] First, Dr. Morris combined MISO and PJM into a single first-tier market to the Duke Power control area. Applicants argue that this ignores transmission constraints between PJM and MISO. Applicants argue that PJM's simultaneous import limit of 7,500 MWs determines the amount of Cinergy generation that can be imported into the Duke Power control area. By placing PJM and MISO in the same first-tier market, Dr. Morris effectively assumes that all of Cinergy's approximately 12,000 MW of generation located in MISO is available for delivery into the Duke Power control area at the Duke-PJM interface, a physical impossibility in light of PJM's simultaneous import limit.[39] Applicants claim that there is no direct interconnection between MISO and Duke, further undermining Dr. Morris' assumption on deliverability of Cinergy imports to Duke.[40]

50. Applicants also argue that Dr. Morris' assumption deviates from the Commission's Appendix A filing requirements. The Commission has held that markets can be defined as a single control area, or, when the control area is part of an RTO, the market can be as large as the RTO.[41] Applicants state that the Commission has never held that two RTOs should be combined into a single market.

51. Second, Applicants contend that Santee Cooper's witness Dr. Morris violated the Appendix A analysis requirements by cutting significant portions of the PJM and MISO markets out from his first-tier market. The Commission has held that, if an RTO is used as a market instead of a single control area, the entire RTO should be treated as a single market unless there are transmission constraints that would cause the market to be separated.[42] Applicants state that Dr. Morris did not identify any transmission constraints that would cause him to lop off the portions of the MISO and PJM markets that he did not include in his combined MISO-PJM market. Applicants argue that Dr. Morris' adjustments are not validated by transmission constraints and are therefore invalid.

***10** 52. Applicants also challenge three secondary changes that Dr. Morris made in his analysis: seasonal variation of TTC data,;use of Southern Company TTC data for the Duke-Southern Company interface; and exclusion of portions of the MISO market northwest of the states of Missouri and Illinois. They say that Dr. Hieronymus' use of TTC data is a conservative choice not mandated by Commission regulations. Quoting section 33.3(c)(4)(i)(C) of the Commission's regulations, Applicants state that transmission imports are supposed to be allocated based on Available Transmission Capacity (ATC). They add that PJM consistently posts zero ATC between PJM and the Duke Power control area, so Dr. Hieronymus' use of any measure of TTC at all, instead of ATC, is conservative. Moreover, Dr. Hieronymus' choice of TTC data for May is a conservative choice, because it is the highest TTC value posted for the year.[43]

53. Applicants state that Dr. Hieronymus' use of Duke TTC values for the Duke-Southern Company interface was appropriate, even though these values were higher than those used by Southern Company, because Dr. Hieronymus did not calculate imports into the Duke Power control area by adding together the TTC postings at each interface. Rather, Dr, Hieronymus limited imports into the Duke Power control area based on Duke's simultaneous import limit. He then allocated the simultaneous import limit among Duke's interfaces pro rata based on Duke's TTC at each interface. Applicants argue that Dr. Hieronymus had to use the Duke value at this interface, or his result would have been a TTC inconsistent with Duke's study.[44] Applicants say that Dr. Morris' exclusion of MISO from the Appendix A Analysis is inconsistent with reality.

54. Applicants contend that, even if the adjustments made by Dr. Morris were accurate, they are irrelevant. They state that the cumulative impact of the three adjustments is to raise the HHI for Economic Capacity by only 13-30 points with similar increases in the HHI for Available Economic Capacity.[45]

55. Applicants argue that even if Santee Cooper's market analysis were accepted, that does not mean that it has demonstrated that the proposed merger would have an adverse impact on competition in the Duke Power control area. Applicants remind the Commission that if horizontal screen violations are shown, then it is necessary to evaluate whether there is in fact any effect of a merger on competition. Applicants contend that the proposed merger will not harm competition because Cinergy's generation is hundreds of miles away from the Duke Power control area. Applicants maintain that Cinergy would not be able to withhold from the Duke Power control area the 100 MWs or so of imports attributed to it by Dr. Morris in light of the capacity competing to sell into the Duke Power control area. Therefore, withholding Cinergy's capacity would not be a threat to competition in the Duke Power control area.[46] Applicants next assert that Dr. Morris' alleged screen failures are "borderline and non-systematic." Because they cannot withhold imports, Applicants state that these screen violations do not raise competitive concerns. Applicants dismiss as dubious any other strategy Cinergy might try to use to increase the price of imports into the Duke Power control area market.

*11 56. Applicants argue that Santee Cooper's assertion regarding a firm/non-firm transmission path is a red herring. There is no reason to assume that a firm path will come into being; Applicants have withdrawn the request for transmission service that they had submitted to PJM. Applicants argue that there is no reason to expect that they could obtain such a path in 2006 - the year their analysis covers - even if they should want to do so, because PJM shows an ATC of zero into the Duke Power control area market.[47] Applicants further state that their screen analysis already addresses the possibility of non-firm transmission between Cinergy and Duke and quantifies the resulting potential impact on the Applicants' market power in the Duke Power control area.[48]

iv. <u>Replies to Applicants' Answer</u>

57. Santee Cooper claims that Applicants' observations regarding the great distance between Duke and Cinergy ignore the fact that the Commission eliminated seams between PJM and MISO with the express purpose of creating a single marketplace. It again cites Dr. Morris' price analysis, claiming it supports a conclusion that the two RTOs effectively function as a single market.

58. Santee Cooper states that the relevant question for the Appendix A analysis of the Duke Power control area is not whether all of the generation in the MISO control area could be imported into PJM at once, but whether the generation has an equal ability to be sold into the Duke Power control area. Because the transfer limits from MISO to PJM exceed the transfer limits from PJM into Duke, the MISO-PJM constraint is non-binding for purposes of an analysis of the Duke Power control area.[49] Santee Cooper argues that in light of the Commission's efforts to create a single marketplace, there is no reason, from an economic perspective, to assume that MISO generation is not similarly situated to generation in PJM to serve Duke. Santee Cooper argues that the Commission has previously indicated that such similarly-situated generation should be treated alike. Thus, the Midwest should be treated as a single market.[50] Dr. Morris' Midwest market is the same as Dr. Hieronymus' MISO-PJM Midwest Market. This implies that Dr. Hieronymus recognized that there was merit in treating overlapping RTO regions as a single market.[51]

59. Santee Cooper argues that it is appropriate to consider transfer capability data from both exporting and importing utilities

in performing an Appendix A analysis because a utility exporting into Duke cannot exceed its own transfer capability at an interface, regardless of whether Duke calculates a higher transfer capability for the same interface. Applicants' analysis of TTC is flawed because Applicants' witness uses a 2003 simultaneous import limit study, while using 2006 TTC data.[52]

60. Santee Cooper further argues that Applicants' use of TTC, rather than ATC, is not a conservative assumption, as Applicants suggest. In the ATC sensitivity analysis of Applicants' Application, ATC results were generally similar to the TTC results. However, Applicants' Answer contained new ATC data purporting to show little or no ATC from PJM to Duke. Santee Cooper claims that Applicants did not update their ATC sensitivity using these data with a consistent methodology, so there is no factual basis for concluding that their use of TTC data is conservative. Santee Cooper provides as a counterexample the case where ATC is zero on every interface into Duke except for TVA. This case could produce greater screen violations for Cinergy, which has generation in TVA, than would be produced by TTC.[53] Santee Cooper also presents a sampling of two data points to supports its claim that Cinergy capacity should receive greater weight because PJM reports more current ATC from Cinergy to Duke and from PJM to Duke.

***12** 61. Santee Cooper argues that Applicants are mistaken in contending that Dr. Morris improperly excluded generation from his analysis. Dr. Morris' exclusion of power produced northwest of the states of Missouri and Illinois was appropriate because such generation is restricted by a binding transmission constraint into the Midwest. However, Applicants fail to mention the location or size of the constraint. Further, Santee Cooper claims that Applicants have misapprehended Dr. Morris' adjustment for eastern PJM generation. Dr. Morris assumed that all generation in PJM was available to serve the Duke Power control area, but his model assumes that generation from eastern PJM would not flow west before flowing south to Duke, but would directly flow south to Duke. Santee Cooper claims that this assumption is more consistent with the physical realities of the system.[54]

62. With respect to the firm transmission path that Santee Cooper alleges the Applicants will pursue, Santee Cooper argues that economic incentive alone is reason enough to assume that the merged company will ultimately secure such a transmission path. They state that the fact that there may be limited ATC between PJM and Duke in 2006 does not support a conclusion that the merged company will never establish such a firm path.[55]

63. Santee Cooper contends that it has demonstrated that there will be an adverse impact on competition in the Duke Power control area. The Commission should not discount Santee Cooper's position simply because no entity within the Duke Power control area has complained about the proposed merger.[56] Santee Cooper grants that the Appendix A screen is not necessarily the end of the Commission's competitive analysis. It states that Applicants have not offered any mitigation measures with respect to the proposed merger and have presented no substantial evidence that the screen violations identified by Santee Cooper are benign.

64. First, Santee Cooper states that the screen violations are not borderline and non-systematic. Treating the Midwest as a single first-tier market to Duke, Dr. Morris finds screen failures for Available Economic Capacity for the entire winter season, and three screen failures for Economic Capacity. Factoring in his additional adjustments, Dr. Morris finds screen failures in seven out of ten periods for Economic Capacity and four out of ten periods for Available Economic Capacity. Because the Duke Power control area is highly concentrated, Santee Cooper argues, the Commission should not overlook these screen failures.[57]

65. Second, Santee Cooper disagrees with Applicants' argument that the fact of the small amount of Cinergy imports into Duke in Dr. Morris' results suggests that the merger will not, as a practical matter, present competitive problems, and that other suppliers could fill any gap left by an attempt to withhold Cinergy generation. Santee Cooper claims that these arguments are really just a variation on the Applicants' contention that the screen failures are borderline. Antitrust law and good policy dictate that the Commission evaluate the proposed merger in light of the substantial probability that the combining companies will emerge as a dominant supplier in an increasingly oligopolistic setting.

v. Applicants' Answer

***13** 66. Applicants state that Santee Cooper has raised only three points that require additional discussion. First, Santee Cooper has presented another novel theory of import allocation. Santee Cooper's assertion that PJM and MISO are a single market effectively assumes away the transmission constraints between PJM and MISO. Santee Cooper justifies this approach by arguing that the amount of generation that can be imported into PJM exceeds the amount of generation that can be exported from PJM into Duke, so from an economic perspective, MISO generation is similarly situated to generation in PJM to serve Duke. Applicants state that this novel theory of allocating imports has not been accepted by the Commission in an Appendix A analysis and that the case Santee Cooper cites in support of its theory is not relevant. Santee Cooper's theory would allow numerous transmission constraints to be ignored, dramatically increasing the size of markets used in the Commission's market power analysis, which could have far-ranging implications and lead to absurd results. Applicants claim further that Santee Cooper did not apply this standard consistently in its analysis. If it had, it would have included all of PJM and MISO in its first-tier market and likely would have had to assume larger first-tier markets at other interconnections to the Duke Power control area. Applicants state that consistent application of Santee Cooper's theory would eliminate the appearance of screen failures in its analysis.[58]

67. Applicants reiterate that Santee Cooper improperly excluded large amounts of PJM and MISO generation from the consolidated market. Applicants contend that Santee Cooper misstated Applicants' argument when it asserted that Applicants believe that the generation was excluded from the analysis altogether. Applicants contend that PJM East capacity and certain MISO capacity was relegated to second-tier markets in Santee Cooper's analysis, thereby significantly reducing the impact of that generation as compared to Cinergy capacity that is included in the first-tier PJM market. Applicants claim that only through its inconsistent treatment of the first-tier market was Santee Cooper able to derive the screen failures.[59]

68. Applicants contend that Santee Cooper's argument is not well founded. Applicants state that they have relied on the analysis of Santee Cooper's expert witness to demonstrate the minimal nature of the assumed Cinergy imports into the Duke Power control area. Applicants assert that, recognizing the weakness of its asserted screen failures, Santee Cooper goes on to make general assertions of future harm due to the substantial probability that the combining companies will emerge as a dominant seller in an increasingly oligopolistic setting. Applicants reply that the evidence in this case shows that they are not likely to emerge as a dominant supplier in any market. Applicants argue that Santee Cooper's argument can only be read as an assertion that, after future unspecified mergers and other market changes, Applicants might possess market power in unspecified markets.[60]

***14** 69. Applicants also state that while Santee Cooper has failed to demonstrate any market power problems associated with the merger, Duke has nevertheless entered into a Memorandum of Understanding (MOU) with TVA to upgrade the intertie between their respective systems in order to facilitate additional wholesale transactions and improve reliability. Applicants state that this upgrade will increase the simultaneous import limit into the Duke Power control area by 100 megawatts (MWs) to 600 MWs, depending on the season. The upgrade ensures that the proposed merger will provide a positive net benefit to wholesale and retail customers in the region.

vi. <u>Commission Determination</u>

70. Applicants have shown that the combination of their generation capacity will not harm competition in any relevant market. We address protestors' specific arguments below.

71. In response to Public Citizen's argument that it is not consistent with the public interest that one consulting firm conducts every major analysis, the Commission notes that it does not have the authority to determine the individual or the consulting firm that applicants use to perform their merger analysis. All expert witnesses are paid by one party or another, and we are alert to the possibility of bias in their analyses. However, we do not find anything inherently wrong with a particular firm or individual performing analyses in a number of cases. Therefore, we reject Public Citizen's request to set the matter of any alleged bias on the part of Applicants' economic witness for hearing.

72. With respect to Public Citizen's concern regarding the inadequacy of the HHI, we note that we have already ruled on this issue in Order No. 642. There, we recognized that the HHI statistic is not a perfect measure of a merger's competitive effect, but that it is useful as a conservative screen to identify transactions that clearly do not undermine competition.[61] Accordingly, we find that Public Citizen's argument constitutes a collateral attack on the Commission's regulations and is outside the scope of the current proceeding.

73. We will deny Public Citizen's request that a new market power analysis be performed that includes all of Applicants' power marketing activities. The Commission's Appendix A analysis focused on capacity *controlled* by all potential sellers in

the relevant market. Without control of capacity, whether through ownership of physical assets or through power purchase agreements, sellers cannot harm competition in wholesale energy markets. If Applicants (or any other potential suppliers) gain control of generation capacity through power marketing activities, the Appendix A analysis does consider power marketing activity, but the mere presence of a large power marketing operation, *per se*, does not, in itself, confer any additional market power to on the merged firm, or on any other seller in the relevant market.

***15** 74. AMP-Ohio's concern regarding opportunities for strategic dispatch does not withstand careful scrutiny. AMP-Ohio argues that the combination of assets on either side of a major entry point to the proposed MISO-PJM joint energy market will give Duke opportunities to affect regional prices.[62] First, we note the dissimilarity between this case and *Exelon/PSEG. Exelon/PSEG* involved a claim of opportunity for strategic bidding between entities within the same market. This claim invokes the opportunity for strategic bidding, or withholding on one side of a transmission constraint to affect prices, and thus profitability of generation, on another side of the same constraint.

75. If the line(s) between the two control areas are uncongested, this strategy would not be successful, unless neither control area had access to imports at the common market price in sufficient quantity to replace the withheld generation. This is possible only if either: (1) all other transmission lines into the two areas are constrained; or (2) the amount withheld is so great as to congest the adjoining lines. The first scenario is exceedingly improbable, unless the line connecting the two areas dwarfs all other adjoining lines. The second implies that the firm would have to withhold a great deal of generation, and this strategy is easily detected and would not be profitable.

76. If the line between the two areas is congested, then the price of energy on the uncongested side of the line would be less than that on the congested side of the line. In this case, withholding on the uncongested side would not affect the price of energy on the congested side, unless the total amount of energy withheld were greater than the amount of capacity on the uncongested side available at a price at or below the price on the congested side. Otherwise, production on the uncongested side would just increase to the point of making up for the lost production; prices on the uncongested side would rise, but price on the congested side would remain unchanged.[63] In this case, however, withholding would not be profitable because of the large amount that would have to be withdrawn from the market in order to effectuate the desired price change.

77. If a company on the constrained side were to withhold, this would likely raise price on that same side. However, price on the uncongested side would not rise unless the following conditions were present: (1) the marginal generator is operating at such a high capacity that it could not ramp up to take up the slack; (2) within-control area competition at the margin is slack; and (3) the area is not able to call on imports from other regions to make up the difference. The latter is a high-demand scenario, where the system is operating near capacity, and transmission constraints bind. In this scenario market monitors are exceedingly vigilant against withholding. Thus, even if this strategy were successful, it would likely be discovered and addressed. In summary, the Commission finds that the withholding strategy posited by AMP-Ohio is exceedingly problematic. The Commission does not view this strategy to pose a significant threat to competition.[64]

***16** 78. We reject APPA/NRECA's and the North Carolina Parties argument that the Commission should analyze the instant merger not only on its own specific terms but as a harbinger of change. Under section 203 of the FPA, we must approve a transaction if it is consistent with the public interest; we cannot deny or condition a proposed merger based on speculation about general trends that may or may not occur in the future. Moreover, under the Merger Policy Statement, we examine the effect of a merger or disposition of jurisdictional facilities on competition in the relevant geographic and product markets, a well-established framework for analyzing market competition. The geographic markets are those that would be affected by the proposed merger by eliminating a competitor or a potential competitor in the market. The product markets are capacity, ancillary services, and energy, across a range of season and load conditions. APPA/NRECA refer to the "broader" markets that could be affected by the proposed merger, thus increasing the economic and political market power of the remaining firms, but they do not define those markets. We are aware that, as markets evolve, product market and geographic market definitions can change. For example, the existence of organized markets for ancillary services has made it possible to analyze ancillary services, such as regulation services, as a distinct relevant product market. As another example, as transmission systems are expanded, or rate pancaking is eliminated, the relevant geographic markets can expand. Our standard of review is flexible enough to consider any changes in market structure that ultimately result from the EPAct 2005 and the repeal of PUHCA 1935, but we will not speculate on what general trends might emerge; rather, we will evaluate the effect of the merger on competition based on the record in this case.

79. We reject Santee Cooper's potential competition argument. The Commission agrees with Santee Cooper that the Duke market is concentrated. However, we disagree with the proposition that the acquiring firm's pre-merger presence on the fringe of the target market could possibly have tempered oligopolistic behavior on the part of existing participants in the market, under the circumstances. Santee Cooper has not shown that the Duke Power control area is an oligopolistic market. Moreover, given Cinergy's lack of physical proximity to Duke and the lack of historical sales in the market, Santee Cooper has not presented any evidence to demonstrate that Cinergy was perceived as a potential competitor in the Duke Power control area. The Commission further rejects Santee Cooper's claim that the Commission's principal concern when evaluating the proposed merger must be the substantial probability that post-merger Applicants will emerge as an overwhelmingly dominant supplier in an increasingly oligopolistic setting as being wholly subjective. Because the Commission cannot measure the "probability" of which Santee Cooper speaks, we will not speculate on what general trends might emerge. Rather, we will evaluate the effect of the merger on competition based on the record in this case.

*17 80. Santee Cooper's argument that Applicants ought to have treated the Midwest as a single, first-tier market in their analysis does not comport with the Commission's Merger Filing Requirements.[65] While the Commission has taken steps to ensure that MISO and PJM act as a single market, none of these steps have eliminated transmission constraints between the two control areas. Santee Cooper notes the high correlation between real-time pricing in MISO and PJM; however, this argument applies to whether MISO and PJM ought to be considered as a common *destination market*, not to the ability of suppliers *to reach* a destination market. Further, the Commission agrees that in the absence of identified transmission constraints, Dr. Morris' decision to dispense with portions of the MISO and PJM markets in his combined MISO-PJM market is arbitrary; we also agree with Applicants' argument that once the Commission accepts Applicants' market definition, Santee Cooper's secondary arguments are inconsequential. Moreover, the screen failures shown in Dr. Morris's analysis are the result of less than 100 MWs of Cinergy's generation assets reaching the Duke destination market, not the elimination of a competitor.

81. Finally, Santee Cooper cites Duke's MOU with TVA to upgrade the intertie between their respective systems as evidence that the merger gives Duke and Cinergy an economic incentive to use transfer capability on a firm contract path from Cinergy to Duke. Santee Cooper's witness finds that the increased transfer capability causes an additional screen failure in the Duke market. We find that the merger does not harm competition in the Duke market for the reasons stated above, namely, that: (1) the merger does not eliminate a competitor in the Duke market; and (2) the screen failures shown in Dr. Morris's analysis are the result of a small amount of Cinergy's generation capacity reaching the Duke destination market, which does not alter the competitive dynamics in the market.

82. Santee Cooper notes that the MOU has not been filed, and argues that the Commission should not base its merger approval, even in part, on a document it has not even seen. We agree with Santee Cooper that we could not rely on an MOU that has not been filed. However, we do not rely on the MOU in finding that the merger will not adversely affect competition in the relevant markets. While we encourage transmission expansion, we will only condition merger approval when there would otherwise be harm to competition, and Applicants have shown that the merger will not harm competition in the relevant markets.

83. Therefore we conclude that the horizontal aspects of the merger will not harm competition in any relevant market. There is very little overlap between Duke's and Cinergy's generating capacity. The MISO market, where Cinergy's capacity is located, is not concentrated, and the combination of Cinergy's generation and Duke's generation that could reach the MISO passes the Competitive Analysis Screen for all season/load levels. The Duke market is highly concentrated, with Duke being the dominant firm in that market, but the proposed merger does not eliminate a competitor in that market. Cinergy does not have any significant presence in the Duke market, so the combination of the two cannot reduce competition. Even if we accepted protestors' revisions to Applicants' analysis, which would show screen failures in the Duke market by allowing more of Cinergy's generation to reach the Duke destination market, the fundamental competitive conditions in the market would not be changed by the proposed merger.[66] We addressed the issue of screen failures caused by factors other than the elimination of a competitor in *NSP*.[67]

B. <u>Vertical Market Power Issues</u>

i. <u>Applicants' Analysis</u>

***18** 84. Applicants state that the proposed merger raises no material vertical market power issues. Applicants' witness, Dr. Hieronymus, states that Applicants cannot use either transmission ownership fuel supplier or fuels delivery systems to hinder competing generation.

85. First, Dr. Hieronymus states that the proposed merger does not increase the Applicants' ability or incentive to use control over their transmission facilities to harm competition in wholesale electricity markets, which is the Commission's concern in such vertical combinations. Dr. Hieronymus states that the vast majority of Duke's generation in MISO and PJM is not in the footprint of Cinergy's transmission system. He states that Cinergy's generation is in MISO where Duke only owns one generation facility. He explains that the Cinergy electric transmission systems are controlled by MISO and that Duke Power's transmission system is subject to an OATT. He adds that Cinergy does not control any generation served by Duke Power's transmission. Thus, Dr. Hieronymus concludes that no transmission-related vertical market power issues are raised by the proposed merger.

86. Applicants also address the effect of combining their natural gas distribution and electric generation assets. Dr. Hieronymus notes that in order for there to be a vertical market power issue, both the upstream and downstream markets need to be highly concentrated.[68] He states that, as demonstrated through his vertical market power analysis, both the upstream and downstream markets are not concentrated.[69]

87. Dr. Hieronymus explains that the proposed merger raises no competitive concerns related to combining Duke's natural gas pipeline assets and Cinergy's generation in MISO because the relevant gas transportation markets are not highly concentrated.[70] He states that the only interstate natural gas pipeline company owned by Duke that runs through MISO is Texas Eastern Transmission, L.P. (Texas Eastern). Dr. Hieronymus adds that there are a significant number of pipelines competing with Texas Eastern for deliveries into MISO. The delivery capacity of Texas Eastern accounts for less than 10 percent of delivery capacity into relevant markets.

88. With respect to the analysis of the downstream market, Dr. Hieronymus states that the Commission's regulations require attributing gas-fired generation to the entity that transports fuel.[71] He presents two examples related to the proposed merger: Duke as an owner of a pipeline serving MISO and Cinergy as a local distribution company. He argues that since the relevant electricity market is unconcentrated, the downstream market would be concentrated only if gas-fired generation were a major part of the generation mix and the newly-affiliated pipeline were the dominant gas transportation supplier. He states that neither is the case. Nonetheless, Dr. Hieronymus does conduct the analysis required under Part 33.4, where he assigns control of the gas-fired generating units to the owner(s) of the pipeline serving those units. His analysis shows that the markets remain unconcentrated, with post-merger concentration levels ranging from 448 HHI to 916 HHI - well below the Commission's 1,800 HHI threshold. Thus, Dr. Hieronymus concludes that the proposed merger passes the vertical market power screen.

***19** 89. Dr. Hieronymus also concludes that there are no vertical market power issues related to Cinergy's ownership of local distribution companies and KO Gas Transmission, an interstate pipeline system delivering to the citygates of its local distribution companies, because the KO Gas Transmission pipeline does not serve any gas-fired generating units and Cinergy's local distribution company operations do not serve any competing gas-fired generating units.[72]

90. Dr. Hieronymus states that he found no other barriers to entry that raise concerns. He states that Applicants do not have dominant control over generating sites, and there has been substantial entry into relevant markets.

91. Applicants state that the transfer of the DENA generation assets to CG&E will not raise "safety net" issues that have been raised in recent cases involving transfers from merchant generation companies to affiliated franchised electric utilities. First, they argue that the transfer of the DENA generation assets to CG&E was negotiated as part of the arm's length negotiations between the Applicants - who were unaffiliated at the time - that led to this proposed merger. Second, they assert that CG&E cannot provide a "safety net" for DENA's generation assets because under Ohio's restructuring statute, CG&E does not charge cost-based generation rates, and no customer, retail or otherwise, can be required to pay costs attributed to the asset transfer.

ii. <u>Protests</u>

92. AMP-Ohio questions Applicants' representation that the combination of Cinergy's generation fleet with Duke's pipeline does not raise vertical market power issues. It states that Dr. Hieronymous' vertical market analysis is based on static conditions that are not realistic in today's dynamic competitive market. The merged entity will own and control extensive pipeline capacity in a region in which it will also compete for sales of generation. Thus, AMP-Ohio argues that the proposed merger could provide opportunities or incentives for the combined company to engage in anticompetitive behavior.[73]

93. AMP-Ohio recommends that the Commission require joint ownership of Cinergy's transmission system by load serving entities. It contends that increasing diversity of ownership in a regional transmission system provides several procompetitive benefits, such as reducing incentives of vertically integrated utilities to deny access to the transmission system, providing joint owners a direct role in transmission planning, and providing new funding sources for network expansion.[74] This arrangement will ensure that LSEs have transmission access if MISO is disbanded in the future.[75]

94. Public Citizen argues that the merger will result in Duke controlling too much natural gas pipeline capacity. It states that combining Duke's extensive natural gas system with Cinergy's KO Gas Transmission pipeline system raises market concentration concerns that can be alleviated through divestiture of Texas Eastern.[76]

iii. <u>Applicants' Answer</u>

***20** 95. Applicants state that AMP-Ohio's arguments about their ability to exercise vertical market power ignores Dr. Hieronymus' vertical market power analysis.[77] Applicants state that there is no evidence to suggest that MISO will cease operations; therefore, there is no reason to grant AMP-Ohio's request to require CG&E to transfer ownership of its transmission facilities to LSEs in Ohio.[78] They argue that AMP-Ohio has not explained: (1) how the termination of MISO would impact the competitive analysis, and (2) how joint ownership would better enable Cinergy to take competitive advantage of a dissolution of MISO. Thus, Applicants contend that there are no grounds for granting AMP-Ohio's request.[79]

96. Applicants disagree with Public Citizen's assertion that the combination of Duke's pipeline system with Cinergy's KO Gas Transmission pipeline system presents competitive concerns for Midwest consumers. Applicants note that Public Citizen does not specify what those concerns are and does not challenge the validity of the vertical market power study performed by Dr. Hieronymous. Applicants argue that because the KO Gas Transmission pipeline system does not serve any unaffiliated electric generation facilities, either directly or indirectly, the combination of the two pipeline systems cannot increase the Applicants' ability to exercise market power.[80]

iv. <u>Commission Determination</u>

97. We find that the proposed merger will not create or enhance vertical market power either through the combination of electric generation and transmission assets or the combination of electric generation and fuel sources. We also find that CG&E's acquisition of the DENA Midwest Assets will not harm competition through vertical foreclosure. We discuss the specific issues below.

98. Applicants have shown that the combination of generation and natural gas distribution facilities will not harm competition. In Order No. 642, we stated that in order for a merger to create or enhance vertical market power, both the upstream and downstream markets must be highly concentrated.[81] Applicants' witness has demonstrated that neither the upstream markets nor the downstream markets are highly concentrated, nor will they be after the merger.[82] Thus, there would not be the possibility of market foreclosure or raising rivals' costs in order to harm competition.

99. Applicants have also shown that the combination of their generation and transmission facilities will not harm competition. Applicants' transmission systems are generally remote from each other's generation, so there is no incentive or ability to exercise vertical market power. Cinergy has turned over operational control of its transmission facilities to the MISO, so it cannot use its transmission assets to harm competition in downstream electricity markets. In addition, because Duke Power's transmission system is far removed from Cinergy's generation assets, which are in MISO, it would not be able to use control of its transmission assets to harm competition in the relevant downstream electricity markets.

***21** 100. We agree with Applicants that requiring CG&E to transfer ownership of its transmission system to LSEs in Ohio is unnecessary. AMP-Ohio has presented no evidence indicating that MISO may cease operations in the future. Moreover, in reviewing an application under section 203 of the FPA, the Commission looks for changes that could enhance the ability or incentive of a company to engage in anticompetitive behavior. The likelihood of continued operation of MISO is not relevant to that determination.

101. We disagree with Public Citizen's assertion that the merger will result in Duke controlling too much natural gas pipeline capacity. Applicants analyzed the effect of combining Duke's natural gas transportation interests with Cinergy's electric generation assets and demonstrated that the merger does not present vertical market power concerns. Using the Commission's attribution method, which assumes that the owner of the pipeline capacity serving a gas-fired generator controls the electric generation capacity, Applicants have shown that the relevant downstream electricity markets are not highly concentrated, as required by Order No. 642. Public Citizen has not provided a basis for the Commission to determine otherwise. Therefore, we find that divestiture of Texas Eastern is not warranted.

C. Safety Net Issue

i. Protests

102. Ohio Consumers' Counsel, AMP-Ohio, and Public Citizen argue that there is a safety net issue relating to the transfer of the DENA merchant plants to CG&E. It asserts that the sale will allow Applicants to combine unprofitable merchant plants with the assets of a regulated electric utility and to charge Ohio customers for capital and operating costs associated with those plants.[83] It further contends that that the purchase of the DENA plants by CG&E shows a preference for the output of high cost plants that are currently owned by DENA and that this violates the Public Utilities Commission of Ohio's (PUC-Ohio) corporate separation plan.[84]

103. Ohio Consumers' Counsel states that the cost of the DENA plants exceeds current market prices for similar generation facilities. It argues that the sale was overvalued because the proposed merger was not made at arm's length, as claimed by Applicants[85] and offers examples of sales of other generating facilities in the Midwest market that were sold at a lower dollar per megawatt basis than the DENA plants.

104. Ohio Consumers' Counsel disputes Applicants' claim that CG&E does not charge cost-based generation rates.[86] It argues that CG&E currently operates under a rate stabilization plan approved by the PUC-Ohio that is based on CG&E's generation costs and is effective through 2008. Under the rate stabilization plan, CG&E charges customers various non-bypassable fees related to generation, fuel, and purchased power. The plan also provides for an annual adjustment fee related to other generation charges. Thus, Ohio Consumers' Counsel contends that CG&E charges regulated, cost-based generation rates, and that consumers can be harmed by the sale of the DENA plants because the costs related to the sale could be passed through to them. In a separate PUC-Ohio docket, CG&E applied for approval of: certain parameters within which CG&E can purchase or build generation facilities; to recover certain costs and a reasonable rate of return on the capital investment in such generating facilities; and to recover such costs and return through its system reliability tracker through 2008 and through a non-bypassable market-based standard service offer charge after 2008. It concludes that CG&E plans to charge Ohio's retail customers for the costs of newly acquired generating plants by means of a system reliability tracker charge through 2008 and a non-bypassable distribution charge that would extend beyond 2008.[87]

***22** 105. AMP-Ohio also challenges Dr. Hieronymous' statement that there is no safety net because CG&E is not subject to rate-base regulation. It states that Ohio's experience with retail access has been mixed, leading some observers to question how long retail choice will continue in Ohio. The possibility that the DENA merchant plants could be part of the rate base in the future gives rise to the safety net issue.[88] It concludes that, because the perception of a safety net discourages entry by other potential suppliers of generation sources, wholesale and retail competition would be harmed.[89]

106. Similarly, Public Citizen states that this transfer of "unregulated" generation violates the Commission's policy on transfers of assets between affiliates.[90] This asset transfer will take place only after DENA and CG&E become affiliates. It states that the Duke-Cinergy merger agreement is written so as to assure that this asset transfer does not occur unless the merger is consummated. In addition, it argues that CG&E has a virtual monopoly over the residential customers in its service territory because no alternative electricity supplier offers service.[91] Public Citizen is concerned that the "unregulated" generation will be included in CG&E's revenue requirement, thus leading to rate increases for consumers.

ii. APPLICANTS' Answer

107. Applicants state that the protestors have not raised any legitimate issues that should prevent the transfer of the DENA assets to CG&E. They state that none of the protestors allege that the transfer of the DENA assets will affect competition or prevent unaffiliated generation companies to compete with the Applicants.[92]

108. Applicants assert that Ohio Consumers' Counsel is wrong about CG&E's ability to pass through the costs of the DENA assets in its retail rates and that it misstates the terms of the Ohio Restructuring Act and the current settlement and PUC-Ohio order related to CG&E's default service rates. They add that many of Ohio Consumers' Counsel's arguments relate to implementation of the Ohio statue, which is not relevant to this proceeding.[93]

109. Applicants state that CG&E operates as a provider of last resort and charges market-based rates under a Rate Stabilization Plan that was approved by the PUC-Ohio in 2004 and is effective through 2008. The plan allows CG&E to charge customers various fees that include a rate stabilization charge for provider of last resort service and an annual adjustment charge to maintain capacity margins and to recover costs associated with homeland security, taxes, environmental compliance, and emission allowances. Applicants note that CG&E must apply to the PUC-Ohio each year for all increases to the rate stabilization charge and annual adjustment charge for a determination of whether the increases are reasonable.

110. Applicants state that CG&E is limited to providing a default service at market-based rates for those customers who have not switched service providers. CG&E has no assurance of the recovery of any costs associated with the DENA assets, even if it could include those costs in its default service rates, because its default customers can switch to an alternative supplier. Applicants further maintain that CG&E cannot recover the costs of the DENA assets in its default service rates because those rates are limited to the recovery of certain costs associated with its existing generation.[94]

***23** 111. Applicants disagree with Ohio Consumers' Counsel that Cinergy is overpaying for the DENA assets. It performed simplistic calculations to determine the value of the plants using the cost per megawatt of capacity purchased in several recent acquisitions. Such calculations do not take into consideration other factors that could influence the price, such as the type of capacity being purchased. Applicants state that the DENA assets are combined cycle units that are expected to cost more than the simple cycle units used as examples by Ohio Consumers' Counsel. Regardless of the price paid for the DENA assets, under existing Ohio law and CG&E's default rate settlement, CG&E cannot recover the costs of the assets in rates.[95]

112. Finally, Applicants disagree with Ohio Consumers' Counsel's argument that the transfer of the DENA assets to CG&E violates the corporate separation requirements of Ohio law. However, they state that they will not address that issue here because that issue is under state, not Commission, jurisdiction.[96]

iii. Commission Determination

113. In *Ameren*,[97] the Commission established guidelines, which are based on its decision in *Boston Edison Company Re: Edgar Electric Co.*,[98] for reviewing under section 203 mergers that involve the acquisition of an affiliate's assets and their effect on competition.[99] Acquisitions involving affiliates have an inherent potential for discriminatory treatment in favor of the affiliate. Affiliate preference when acquiring assets can have serious adverse effects on competition and may therefore not be consistent with the public interest.

114. Applicants state that they intend to transfer the DENA Midwest Assets to CG&E as part of the proposed merger in order to achieve operating efficiencies and to diversify fuel risk. They state that the opportunity to consolidate these assets was an important factor in their decision to enter into the proposed merger.[100] However, Applicants have not provided evidence that the transfer agreement was in fact negotiated before the merger announcement. Indeed, given the contemporaneous nature of the mergers, it is reasonable to assume that the initial negotiations regarding the merger took place simultaneously with negotiations regarding the assets. Therefore, we find that the self-interest of the merging partners converged sufficiently, even before the consummation of the merger, to compromise the market discipline inherent in arm's-length bargaining.[101] Moreover, as argued by Public Citizen, when the asset transfer does occur, the two corporations will in fact be one merged entity, so the exchange will be an affiliate transaction. Therefore, we will treat the two entities as affiliates, and analyze the transfer's effect on competition accordingly.

115. In *Ameren*, we were concerned that affiliate preferences, or the possibility thereof, in asset acquisitions may harm competition. However, as we recognized in *Ameren/Illinois Power*, in order for a profit-maximizing firm to have an incentive to pay an inflated price for an asset (in that case, a power purchase agreement), it must be able to pass on those inflated costs to captive, cost-based ratepayers:

> ***24** Finally, for 2007 and beyond, Illinois Power's retail load obligations will be served through a competitive bidding process that will ensure that competitors are not foreclosed. Moreover, we note that Illinois is under a retail rate freeze through 2006. The PPAs are for 2005 and 2006, so there will be no time when they are in effect and Illinois is not under a retail rate freeze. Therefore, Illinois Power would be unable to pass any inflated power purchase costs onto customers. This eliminates Applicants' incentive to engage in regulatory evasion though the PPAs. The Commission finds that Applicants have shown that the PPAs do not serve as a vehicle for vertical foreclosure in this case.[102]

Here, as in *Ameren/Illinois Power*, CG&E would not be able to pass on inflated costs to captive ratepayers because the Ohio restructuring limits CG&E to the recovery of certain costs associated with its *existing* generation, not newly-acquired generation. Therefore, we reject protestors' arguments that the DENA transfer could harm competition by vertical foreclosure.

116. We also clarify that the "safety net" concern discussed in *Ameren* is restricted to vertical foreclosure through regulatory evasion, which is relevant only if a utility can pass inflated costs onto captive cost-based customers. We also note that in such circumstances, there are a number of ways to show that no such affiliate preference occurred, including review of competitive solicitation processes by the relevant state commissions.

2. Effect on Rates

A. Applicants' Analysis

117. Applicants contend that the proposed merger will have no adverse effect on rates charged to wholesale power and transmission customers. They commit to hold these customers harmless from any wholesale or transmission rate increases resulting from costs related to the merger for a period of five years, to the extent that such costs exceed merger-related savings. In order to meet this commitment, Applicants request authorization to defer merger-related savings to the extent that they are not otherwise deferred under generally accepted accounting principles.

B. Protests

118. Dayton states that the merger may affect CG&E's operation of units that Dayton jointly owns with CG&E (Jointly-Owned Units). It requests that the Commission establish an evidentiary hearing, settlement judge procedures, or a technical conference to assess the effect of the merged entity's operation of the Jointly-Owned Units on Dayton as well as on competition, rates, and regulation. It also asks that we condition approval of the merger to ensure that Dayton and its ratepayers will be held harmless from any adverse impacts, such as increased costs or additional risks and liabilities.[103]

119. Public Citizen states that the proposed merger will increase rates because the costs of the merger will be passed on to consumers. It states that Applicants have requested the Ohio Public Utilities Commission to authorize collection of costs, net of savings, associated with the merger, which Public Citizen claims violates the FPA.[104] It notes that Applicants acknowledge that there are no guarantees of merger-related savings.

C. Applicants' Response

***25** 120. Applicants state that Dayton and Cinergy have negotiated agreements regarding the operation of the Jointly-Owned Units, and argue that Dayton can protect itself by enforcing its rights under those agreements.

D. Commission Determination

121. In the Merger Policy Statement, we explained the need for ratepayer protection. The Merger Policy statement also describes various commitments that may be acceptable means of protecting ratepayers in particular cases, such as the hold

harmless commitment offered by the Applicants. Thus, we find that Applicants have shown that the proposed merger will not adversely affect wholesale or transmission rates, and we rely on their hold harmless commitment in making this finding.

122. As discussed above, Ohio Consumers' Counsel, AMP-Ohio, and Public Citizen raise the question of ratepayer protection as related to the "safety net" issue. They claim that CG&E operates under regulated, cost-based rates, which could result in the costs of the DENA plants being passed through to ratepayers. However, we find that the hold harmless commitment will shield ratepayers from adverse rate impacts. Applicants also state that no ratepayer will pay for the costs of the DENA plants because, under the PUC-Ohio order regarding CG&E's market-based default rates, only costs associated with existing generation - not newly-acquired generation - can be recovered.[105] Given these protections, we agree with Applicants that issues related to CG&E's cost recovery and rate structure are not relevant to our decision here.

123. We will deny Dayton's request for an evidentiary hearing on the effect of the merger on the operation of the Jointly-Owned Units and will not impose conditions. Applicants' hold-harmless commitment, along with the agreements regarding the operation of the Jointly-Owned Units, provide adequate ratepayer protection. Dayton has not shown that the proposed merger will not alter Dayton's rights or Cinergy's responsibilities under their agreements.

3. <u>Effect on Regulation</u>

A. <u>Applicants' Analysis</u>

124. Applicants state that the proposed merger will not adversely affect federal regulation. They state that the proposed merger will create a new registered holding company, subject to the regulation by the Securities and Exchange Commission (SEC) under PUHCA 1935. Applicants commit that, for wholesale ratemaking purposes, they will follow the Commission's policy regarding the pricing of affiliate transactions for non-power goods and services. Applicants state that this commitment ensures that Duke, Cinergy, and their affiliates will remain subject to the Commission's regulation regarding wholesale ratemaking effects of affiliate non-power transactions and eliminates any potential concern of the Commission regarding wholesale ratemaking impacts of affiliate non-power transactions and eliminates any potential concern of the Commission regarding the preemptive effect of SEC jurisdiction under the holding in *Ohio Power Co. v. FERC*.[106]

***26** 125. Applicants state the proposed merger will not adversely affect state regulation. They are filing applications for approval of the proposed merger with four of the five affected state commissions and argue that those state commissions will have the ability to protect their own jurisdiction.

126. Applicants state that, while the Indiana Commission does not have jurisdiction over the merger, it will have the opportunity to consider PSI's request for approval of various affiliate relationships related to the proposed merger and for accounting referral for certain merger-related costs. They state that DENA's proposed transfer of its 75 percent interest in the Vermillion Energy Facility (Vermillion) to CG&E may require approval and/or an order disclaiming jurisdiction over the transaction from the Indiana Commission. Because Vermillion is a merchant generating plant that does not provide retail service within Indiana, the Indiana Commission has declined to exercise its jurisdiction over Duke Vermillion with respect to the construction, ownership, and operation of the facility. Finally, Applicants argue that because the proposed merger will not change PSI, its business, its assets, or its regulatory status, it will not adversely affect Indiana Commission's ability to regulate PSI.

B. <u>Protests</u>

127. The Indiana Commission states that it lacks full authority to act with respect to the proposed merger, and therefore may not be fully able to fulfill its regulatory duties without the assistance of the Commission. It states that commitments made to the Indiana Commission by CG&E and PSI Energy at the time of the merger forming Cinergy may not be operative. A key concern addressed in the settlements involving that merger was the preservation of the Indiana Commission's ability to maintain proper regulatory oversight regarding the components of the charges to be passed through to Indiana ratepayers, who are under a cost-of-service regulatory system. The Indiana Commission states that approval of the proposed merger should be conditioned on state regulators such as the Indiana Commission retaining the full authority traditionally exercised to assess and make orders with respect to mergers between PSI and its affiliates insofar as those mergers affect retail rates. It requests that the Commission send this matter to settlement discussions. The Indiana Commission also argues that the merger

will create a multi-state holding company covering some states where rates are set by competitive forces and other states where they are set by cost-based regulation, which,, combined with the repeal of PUHCA 1935, may result in unintended consequences.

128. Santee Cooper, AMP-Ohio, Public Citizen, and Dayton argue that Applicants should explain the steps they will take to ensure that improper cross-subsidization or cross-collateralization will not occur as a result of the merger. Santee Cooper argues that, although the merger application was filed before the enactment of EPAct, August 8, 2005, it was not complete until August 18, 2005, when Applicants supplemented their application. It concludes that the EPAct 2005 standards should apply. AMP-Ohio raises the possibility that the merged firm could, for example, build a generating facility in North Carolina, then use that capacity to serve load in Ohio, while receiving cost recovery through North Carolina customers' cost-based rates.

C. Applicants' Response

***27** 129. In response to the Indiana Commission's concerns, Applicants reiterate that while the Indiana Commission will not approve the overall merger, it has the authority to address the issue it raises in its protest - affiliate agreements related to the proposed merger. Applicants further argue that the repeal of PUHCA 1935 and the enactment of PUHCA 2005 are issues that the Commission is considering in its rulemaking on that subject.[107] Any concerns that a state commission has in this regard should be raised in that proceeding. Applicants also note that PUHCA 2005 states that nothing therein "precludes the Commission or a State commission from exercising its jurisdiction under otherwise applicable law to protect utility customers."[108]

130. In response to protestors' arguments that Applicants should present an analysis of whether the merger will create opportunities for cross-subsidization between regulated and unregulated affiliates within the holding company, Applicants argue that the merger should be reviewed under the Commission's existing standard, rather than the standard that will be in effect after February 8, 2006, when EPAct 2005 becomes effective.[109]

D. Commission Determination

131. Applicants have shown that the proposed merger will not adversely affect federal regulation. We note that the transfer is expected to occur after February 8, 2006 - the date on which PUHCA 2005 will replace PUHCA 1935. However, Applicants filed their application for the proposed merger before the date on which PUHCA 2005 was enacted, August 8, 2005, and thus the current section 203 standards apply to the proposed merger.[110] We find that the transfer will not adversely affect federal regulation, because Applicants have committed that, for wholesale ratemaking, they will follow the Commission's policy regarding the pricing of affiliate transactions for non-power goods and services. We reject protesters' arguments that Applicants should present a specific analysis of whether the proposed merger will create opportunities for cross-subsidization. Furthermore, we have found no evidence that the proposed merger will create opportunities for cross-subsidization, and no protestor has raised a credible scenario whereby the merger increases the likelihood of cross-subsidization. In particular, our discussion of the safety net issue above focuses on the merged firm's ability and incentive to engage in cross-subsidization, and concludes that the proposed merger will not create such opportunities because of the regulatory safeguards in place.

132. We deny the Indiana Commission's requests that we place the proceeding on a settlement track and condition our approval of the merger on state regulators retaining their authority regarding mergers that affect rates paid by retail ratepayers. The Indiana Commission raises the concerns that the merger will create a multi-state holding company covering some states where rates are set by competitive forces and other states where they are set by cost-based regulation. As noted by Applicants, PUHCA 2005 is not intended to prevent any state commission from exercising its jurisdiction under otherwise applicable law to protect utility customers. Moreover, Indiana Commission retains jurisdiction over the affiliate transactions with which it is concerned.

C. Other Issues

1. Protests

***28** 133. Public Citizen states that representatives of the Applicants held multiple private meetings with some or all of the Commissioners before the companies' July 12 filing at the Commission and after the companies filed details of the merger with the Securities and Exchange Commission. Public Citizen requests that all participants in any and all of these meetings with the Commissioners—including the Commissioners themselves—testify under oath what was discussed at the meetings, and that this testimony shall be provided as part of the public record of this proceeding.

134. Public Citizen states that it is making this request because Commissioners are required by the Administrative Procedure Act (APA),[111] to record meetings if they have knowledge that the matter will be "noticed for hearing." According to Public Citizen, the Commission should have known that the Duke-Cinergy merger would be "noticed for hearing" because on May 27, 2005, the companies filed a "Stock Purchase Agreement" with the SEC, which provided the public and the Commission notice that the merger was going forward and would have to be filed for approval at the Commission.

135. Public Citizen further contends that Commission rules prohibiting off-the-record communications with "decisional" employees during any "contested on-the-record proceeding," as applied in this case, conflicts with federal law. According to Public Citizen, the Administrative Procedure Act limits the ability of federal agencies to conduct "off-the-record" private meetings: "the prohibitions of this subsection shall apply beginning at such time as the agency may designate, but in no case shall they begin to apply later than the time at which a proceeding is noticed for hearing unless the person responsible for the communication has knowledge that it will be noticed, in which case the prohibitions shall apply beginning at the time of his acquisition of such knowledge."[112]

2. Commission Determination

136. We reject Public Citizen's argument that the Commissioners' pre-filing meetings were in violation of either the Commission's regulations or the APA. First, the regulations prohibit off-the-record communications in any "contested on-the-record proceedings."[113] The regulations define a "contested on-the-record proceeding" as "any proceeding before the Commission to which there is a right to intervene and in which an intervenor disputes any material issue..."[114] The regulations prohibit such off-the-record communications in a contested on-the-record proceeding "from the time of filing of an intervention disputing any material fact that is the subject of a proceeding."[115]

137. At the time that employees of the Applicants met with the Commissioners, the Commission's prohibition against off-the-record communications did not apply because there was no proceeding whatsoever, much less a contested on-the-record proceeding, nor were there any parties. As the prohibition against off-the-record communications did not apply at this point, we find that the Commissioners acted according to the rules set forth in the Commission's regulations.

***29** 138. Second, we reject Public Citizen's argument that any pre-filing meetings between the Commissioners and Applicants violated the APA because, when the pre-filing meetings occurred, there was no "proceeding", so the pre-filing meeting was not an *ex parte* communication. The APA defines an "*ex parte* communication" as "an oral or written communication not on the public record with respect to which reasonable prior notice to all *parties* is not given."[116] A "party" is "a person or agency named or admitted as a party, or properly seeking and entitled as of right to be admitted as a party, in an agency *proceeding*."[117] Prior to filing, as there was no Commission proceeding, the APA's prohibition on *ex parte* communication could not apply. Public Citizen's protest would effectively read out of the statute the requirement that there be an agency proceeding to which parties are named, admitted, or are entitled as of right to seek admission, and we must therefore reject it as inconsistent with the APA's definition of *ex parte* communication. Furthermore, we note that Public Citizen makes no effort to explain when, in its view of the APA, a "proceeding" begins. Under Public Citizen's view, there is no limit to how early a "proceeding begins.

139. In Order No. 607, we similarly concluded that pre-filing meetings are not *ex parte* communications, as defined by the APA. In the Notice of Proposed Rulemaking underlying that order, the Commission proposed to explicitly provide an exemption for pre-filing meetings.[118] However, we determined in Order No. 607 that no pre-filing exemption was necessary and thus that pre-filing communications were not covered by the APA prohibition on *ex parte* communications "because they take place prior to the filing of an application, and therefore prior to any 'proceeding' at the Commission."[119]

140. Public Citizen cites *Electric Power Supply Association v. FERC*[120] to support its argument that the Commissioners' pre-filing meetings violated the APA. However, *EPSA* dealt with *ex parte* communications related to a specific "pending

on-the-record proceeding" and post-filing meetings. The Court indicated in *EPSA* that the overriding concern of section 557 is to ensure that an adequate record exists for purposes of judicial review and that the fairness of the proceedings is above reproach.[121] In the situation at hand, there was no "pending on-the-record proceeding" because no application had yet been filed. Therefore, the APA was not violated.

141. Finally, we note that the current proceeding is not the proper venue for Public Citizen to challenge the validity of the Commission's regulations; its arguments are, in fact, a collateral attack on those regulations. We will not ignore our regulations because a party to a specific case argues that the regulations are invalid. If Public Citizen believes that the Commission should amend its regulations, Public Citizen should submit a petition for rulemaking setting forth the changes it believes are necessary.[122]

The Commission orders:

***30** (A) Applicants' proposed merger is authorized, as discussed in the body of this order.

(B) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever now pending or which may come before the Commission.

(C) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(D) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(E) Applicants shall make any appropriate filings under section 205 of the FPA, as necessary, to implement the Proposed Acquisition.

(F) If the Proposed Acquisition result in changes in the status or the upstream ownership of Applicants' affiliated qualifying facilities, if any, an appropriate filing for recertification pursuant to 18 C.F.R. § 292.207 shall be made.

(G) The Applicants shall submit their proposed final accounting on the merger within six months of the consummation of the merger as more fully discussed in the body of this order. The Applicants shall account for the transfer of the generation assets in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold, of the Uniform System of Accounts as more fully discussed in the body of this order.

By the Commission.

(SEAL)

Magalie R. Salas
Secretary.

Footnotes

1 16 U.S.C. § 824b (2000) (*amended by* Energy Policy Act of 2005 § 1289, Pub. L. No. 109-58, 119 Stat. 594, 982-83 (2005) (EPAct 2005)).

2 *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 Fed. Reg. 68,595 (1996); FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997) (*Merger Policy Statement*); *see also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-Dec. 2000 ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 66 Fed. Reg. 16,121 (2001), 94 FERC ¶ 61,289 (2001) (*Merger Filing Requirements*); *Transactions Subject to FPA Section 203*, Notice of Proposed Rulemaking, 70 Fed. Reg. 58,636 (2005), FERC Stats. & Regs. ¶ 32,589 (2005) (Section 203 NOPR).

3 16 U.S.C. §§ 79a (2000). We note that the EPAct 2005 repeals PUHCA 1935, effective February 8, 2006, and enacts the Public Utility Holding Company Act of 2005 (PUHCA 2005). EPAct 2005, §§ 1261 *et seq.*, Pub. L. No. 109-58, 119 Stat. 594 (2005).

4 16 U.S.C. § 824(b) (2000) (*amended by* EPAct 2005 § 1289).

5 The MISO Submarket is all of MISO, excluding the Louisville Gas & Electric control area, the Wisconsin-Upper Michigan System, Iowa, and Minnesota. MISO-PJM Midwest includes the MISO Submarket and the western part of PJM inclusive of the areas in which Duke Energy North America's PJM assets are located, but exclusive of that part of PJM East of Allegheny Energy, Inc., as well as Dominion Resources, Inc.

6 Each supplier's "Economic Capacity" is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. "Available Economic Capacity" is based on the same factors but subtracts the suppliers' native load obligation from its capacity and adjusts transmission vailability accordingly.

7 Hieronymus Testimony, Exhibit J-1, at 37.

8 Section 10 of PUHCA 1935 requires that any registered public-utility holding company comprise a "single integrated... system" that is "physically interconnected or capable of physical interconnection" and "confined in its operations to a single area or region." 15 U.S.C. § 79j(c)(1) (2000).

9 A sensitivity analysis is a standard statistical procedure designed to test whether the results of the model change significantly due to small changes in key parameters of the model. Results that are not sensitive to changes in key parameters of the model are considered "robust". For example, the results of the Delivered Price Test can be affected by changes in the assumed market price or input prices such as fuel costs. In Order No. 642 the Commission recognized the importance of sensitively analyses: "[g]iven the importance of prices to the outcome of market definition, we will require applicants to perform sensitivity analysis of alternative prices on the predicted competitive effects. This provides us with an additional measure of confidence and assurance that results are reliable." Order No. 642 at 31,891-92.

10 The Herfindahl- Hirschman Index is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1000 points are considered unconcentrated; markets which the HHI is greater than or equal to 1000 but less than 1800 points are considered moderately concentrated; and markets where the HHI is greater than or equal to 1800 points are considered highly concentrated. The Commission has adopted the Federal Trade Commission/Department of Justice Horizontal Merger Guidelines, which state that in, a horizontal merger, an increase of more than 50 HHI in a highly concentrated market or an increase of 100 HHI in a moderately concentrated market fails its screen and warrants further review. U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992).

11 Merger Policy Statement, Appendix A at 30,128 (Competitive Analysis Screen).

12 18 C.F.R. § 33.3(c)(2) (2005).

13 Under the "squeeze-down" allocation method, shares of available transmission are allocated at each interface, diluting as they get closer to the destination market. When economic suppliers are competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic capacity each supplier has outside of the interface. For example, suppose that only two suppliers, A and B, have economic capacity outside of interface X. Supplier A has 60 MW of economic capacity outside of interface X, while Supplier B has 40 MW of economic capacity outside of interface X. By the squeeze down method, Supplier A would be allocated 60 percent of the available transmission at X, and Supplier B 40 percent. So if the transmission capacity at X is 80 MW, Supplier A would be allocated 60 percent, or 48 MW, and Supplier B would be allocated the remaining 32 MW. Under the squeeze-down allocation method, if Supplier A's and Supplier B's generation has to travel through multiple constrained interfaces, their generating capacity squeezing through the constraint will be reduced iteratively, so that their shares of available transmission are diluted as their generation moves closer to the destination market.

14 Hieronymus Testimony, Exhibit J-1, at 51-52.

15 Public Citizen Protest at 5.

16 *Id.* at 6.

17 *Id.* at 7.

18 AMP-Ohio Protest at 8.

19 *Id.* at 9.

20 *Id.* at 2.

21 APPA/NRECA Protest at 5.

22 Santee Cooper at 7 (*citing Kansas Power & Light Co. v. FPC*, 554 F.2d 178 (D.C. Cir 1977); *Central Maine Power Corp*., 55 FPC ¶ 2,477 (1976)).

23 Id. at 8 (citing United States v. Marine Bancorporation, Inc. 418 U.S. 602 (1974)).

24 *Id.* at 8.

25 *Id.* at 12.

26 *Id.* at 17.

27 *Id.* at 18.

28 Id.

29 *Id.* at 19.

30 *Id.* at 19-20.

31 *Id.* at 20.

32 *Id.* at 21.

33 *Id.* at 22.

34 Applicants' Answer at 24, 25.

35 *Id.* at 25 (*citing* 112 FERC 61,011 at P 131 (2005) (*Exelon/PSEG*)).

36 *Id.* at 5-6.

37 *Id.* at 3.

38 *Id.* at 10.

39 *Id.* at 12.

40 *Id.* at 9.

41 *Id.* at 11-12 (*citing* Order No. 642 at 31,884).

42 *Id.* at 13 (*quoting* Order No. 642 at 31,885).

43 *Id.* at 15-16.

44 *Id.* at 16-17.

45 *Id.* at 15.

46 *Id.* at 21-22.

47 *Id.* at 23.

48 *Id.* at 24.

49 Santee Cooper Answer at 4.

50 *Id.* at 5.

51 *Id.*

52 *Id.* at 6.

53 *Id.* at 7.

54 *Id.* at 8.

55 *Id.* at 8-9.

56 *Id.* at 9.

57 *Id.* at 10.

58 Applicants' Answer at 2-3.

59 *Id.* at 3-4.

60 *Id.* at 5-6.

61 Order No. 642 at 31,897.

62 We disagree with Applicants' assertion that this is just an unsupported, general claim of harm that the Commission found in the Merger Policy Statement to be insufficient grounds for further investigation of an otherwise comprehensive analysis developed by the applicants. AMP-Ohio's is a *specific* claim of harm, and as such, deserves further analysis.

63 Since we are examining the effect of withholding on one side on price on the other side of the constraint, as per AMP-Ohio's claim, this is the correct analysis.

64 The Commission views the statement AMP-Ohio cites, namely, that "[t]he Merger will give the combined company significant generation assets that straddle the seam between PJM and MISO with pricing optionality in both energy markets," as a recognition by Duke Energy Corp. that it will have the option of selling energy into either market, selling to the highest bidder. Such a strategy, though, is one of producing output in response to a high price, rather than withholding it.

65 In Order No. 642, the Commission explained that applicants must adjust suppliers' capacity consistent with the physical transmission capacity available to reach the destination market. Order No. 642, at 31,887.

66 We note that as a result of the announced merger, Cinergy does not have market-based rate authority in the Duke market: "Commission policy requires merging utilities to treat one another as affiliates pending the consummation of a merger. In light of the announced merger between Duke Energy Corporation and Cinergy Corporation, Cinergy Companies has committed to treating

Duke Power and its affiliates as affiliates for purposes of the code of conduct. Further, Cinergy Companies has committed that it will not make market-based rate sales to Duke Power and its affiliates without first receiving Commission approval under section 205 of the Federal Power Act. We note, however, that the market-based rate tariffs of Duke Power and its affiliates are not applicable to sales in the Duke Power control area. The Commission imposes this same restriction on the Cinergy Companies' sales in the Duke Power control area." *Cincinnati Gas and Electric, et al.*, 113 FERC ¶ 61,197 (2005).

67 *See Northern States Power Company*, 90 FERC ¶ 61,020 (2000) (*NSP*). In *NSP*, the Commission stated: "it is clear from Applicants' analysis that NSP and SPS do not currently compete with each other in any of the 33 relevant markets analyzed by Applicants. Consequently, under this approach, the merger does not eliminate a rival and create or enhance the ability of the merged company to unilaterally exercise market power by withholding output. We are not generally concerned about increases in market concentration exceeding the thresholds in cases where neither NSP or SPS is a supplier in the relevant market or when the market share of one Applicant decreases."

68 *Id.*

69 Hieronymus Testimony, Exhibit J-1 at 7 and 55.

70 *Id.* at 7.

71 *Id.* at 14.

72 *Id* at 64.

73 AMP-Ohio Protest at 16-17.

74 *Id.* at 18-20.

75 *Id.* at 17-18.

76 Public Citizen Protest at 9.

77 Applicants' Response at 25-26.

78 *Id.* at 4.

79 *Id.* at 8.

80 *Id.* at 26.

81 Order No. 642 at 31,911.

82 Hieronymous Testimony, Exhibit J-1 at 6-7.

83 Ohio Consumers' Counsel Protest at 4.

84 *Id.* at 5.

85 *Id.* at 7.

86 *Id.* at 8.

87 *Id.* at 9.

88 AMP-Ohio Protest at 13.

89 *Id.* at 14.

90 Public Citizen Protest at 9

91 *Id.* at 9.

92 Applicants' Response at 27.

93 *Id.* at 27.

94 *Id.* at 28 (*citing In re CG&E's MBSSO*, PUC-Ohio Case No. 03-93-EL-ATA, Entry On Rehearing at 9-12 (November 2004)).

95 *Id.* at 29.

96 *Id.* at 29.

97 Ameren Energy Generating Company, 108 FERC ¶ 61,081 (2004) (Ameren)

98 *Boston Edison Company Re: Edgar Electric Co.*, 55 FERC ¶ 61,382 (1991) (*Edgar*). In *Edgar*, the Commission gave three examples of how to demonstrate lack of affiliate abuse: (1) evidence of direct head-to-head competition between affiliated and unaffiliated suppliers; (2) evidence of the prices that non-affiliated buyers were willing to pay for similar services from the affiliate; and (3) "benchmark" evidence of the prices, terms and conditions of sales made by non-affiliated sellers. These examples were not an all-inclusive list; the individual facts of a case could bring forth other examples not expressed in *Edgar* to show that a merger is without affiliate abuse.

99 In *Ameren*, the Commission discussed a concern with "safety net" transactions, involving transfers of merchant generation to an affiliated franchised electric utility when the market declines, thus giving the affiliated merchant a "safety net" that merchant generators not affiliated with a franchised utility lack. The Commission was concerned that the existence of a safety net could affect the incentive of new merchant generators to invest in new facilities, erecting a barrier to entry that could harm the competitive process.

100 Application at 30.

101 *See Cenergy*, Inc. 74 FERC ¶ 61,281 (1996) (*Cenergy*).

102 *Ameren Corporation*,108 FERC ¶ 61,094 at P 61 (2004) (*Ameren/Illinois Power*).

103 Dayton Comments at 9-10.

104 Public Citizen Protest at 10.

105 Applicant Response at 28.

106 954 F.2d 779 (D.C. Cir. 1992).

107 Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005, Order No. 667, FERC Stats. & Regs. ¶ 31,197 (2005).

108 Applicants' Answer at 31 (*citing* EPAct 2005 § 1269).

109 *Id.* at 34. Applicants argue that the merger application was filed before the enactment of EPAct 2005, despite Santee Cooper's claim that the Application was not complete until after that date.

110 Section 1289 of EPAct 2005 states that "[t]he amendments made by this section shall not apply to any application under section 203 of the [FPA] that was filed on or before the date of enactment of [PUHCA 2005]." EPAct § 1289(c).

111 5 U.S.C. § 551 *et seq.* (2000).

112 5 U.S.C. § 557(d)(1)(E) (2000).

113 18 C.F.R. § 385.2201(a) (2005).

114 18 C.F.R. § 385.2201 (c)(1) (2005). In Order No. 607, the final rule implementing the Commission's *ex parte* rules, we noted that "[t]he explicit requirement that the proceeding be "contested" before *ex parte* rules attach reflects the notion that procedural requirements and constraints originally developed to preserve the rights of parties in an adjudication have no place in an administrative proceeding in which there is no "contest" comparable to the controversy in a judicial case." *Regulations Governing Off-the-Record Communications*, Order No. 607, FERC Stats. & Regs. ¶ 31,079 at 30,881, 64 Fed. Reg. 51,222 at 51,230 (1999).

115 18 C.F.R. § 385.2201(d)(1)(iv) (2005).

116 5 U.S.C. § 551(14) (2000) (emphasis added).

117 5 U.S.C. § 551(3) (2000) (Emphasis added).

118 *Regulations Governing Off-the-Record Communications*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,534 at 33,506-07 (1998) ("pre-filing communications are often useful in educating applicants as to the appropriate format, content, and form that an application or other filing should take. Such consultations can therefore improve the chances that filings, once made, will be ready for evaluation on the merits.").

119 Order No. 607 at 30,879.

120 Electric Power Supply Association v. FERC, 391 F.3d 1255 (2004) (EPSA).

121 *EPSA*, 391 F.3d at 1266 (2004).

122 18 C.F.R. § 385.207(a)(4) (2005).

113 FERC P 61297 (F.E.R.C.), 2005 WL 3477003

End of Document

122

CONFIDENTIAL – Deposition & Exhibits of Benjamin M.H. Borsch, August 11, 2014, (Confidential FPSC Document No. 04633-14). See also Late Filed Exhibits No. 4, 5, 6 contained on Staff Exhibit CD.

Note: Exhibit No. 3 will not be provided pursuant to an objection for admission by DEF.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 122
PARTY: STAFF
DESCRIPTION: CONFIDENTIAL - Deposition & Exhibits of Benjamin M.H. Borsch, August 11, 2014.(Confidential FPSC Doc...

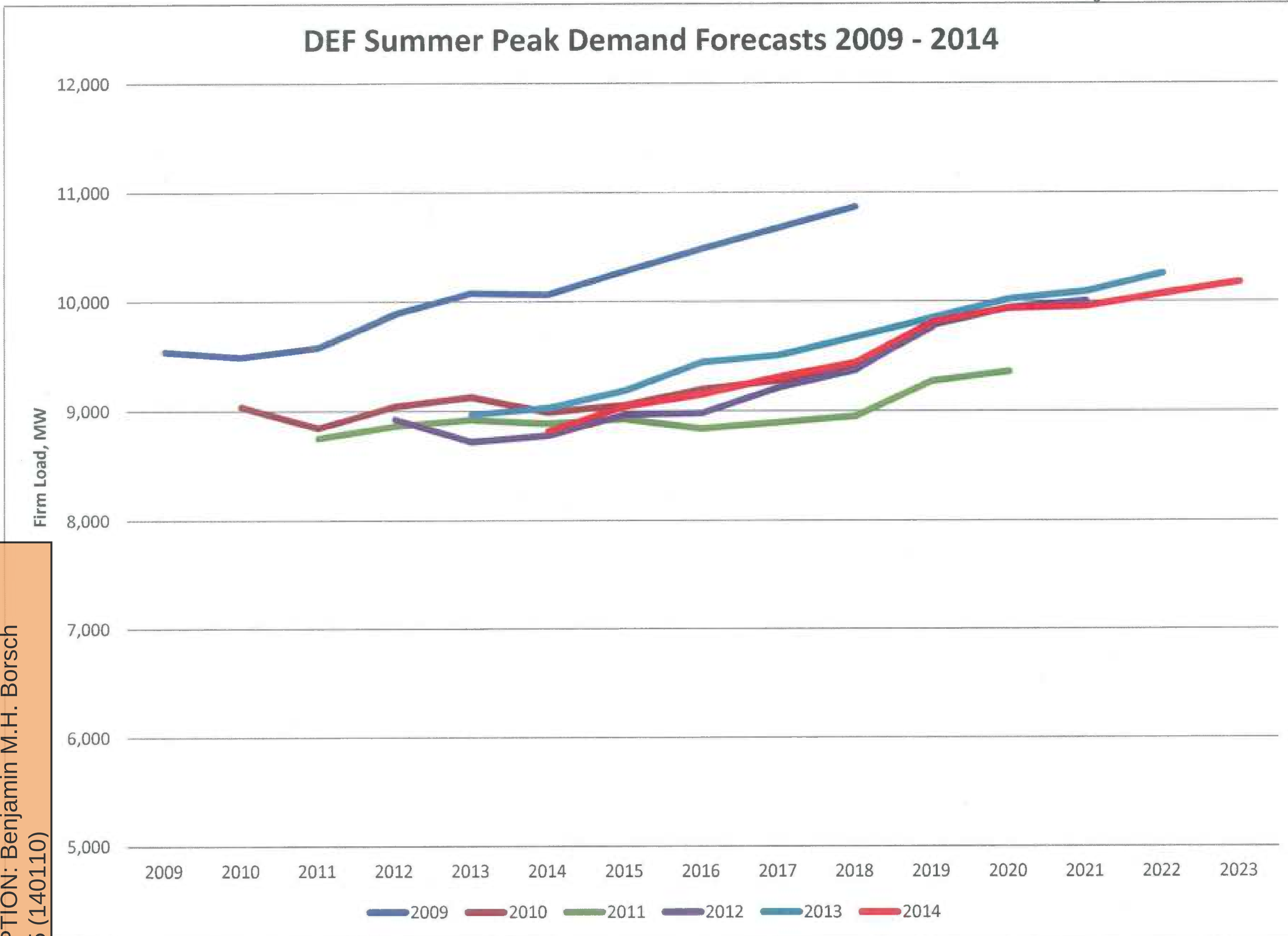
EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 123
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Ed Scott ES-4 (140111-EI)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI   EXHIBIT: 124
PARTY: DUKE ENERGY FLORIDA, INC. –
(REBUTTAL)
DESCRIPTION: Ed Scott ES-5 (140111-EI)

Docket No. 140110-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-15)
Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 125
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-15 (140110)

Fixed Costs changes associated with Citrus Delay and CRS Extension

		CPVRR ($M)	
Citrus Delay	Differential - Generation Capital	($61.75)	
Citrus Delay	Differential - Fixed O&M	($6.22)	
Citrus Delay	Differential - Gas Reservation Charges	$13.28	
		($54.69)	
CRS Extension	Differential - Capital RR	$0.46	
CRS Extension	Differential - O&M Capital Budget	$18.55	
CRS Extension	Differential - O&M Alternate Coal	$0.84	
	Differential - Ongoing Capex Annual Budget	$2.46	
		$21.85	
	Seasonal Purchases	$16.75	
	Fixed Costs associated with Citrus Delay and CRS Extension	($16.09)	Savings

Production Costs changes associated with Citrus Delay and CRS Extension

Btm ash cost	$1.34	
CaCO3 cost	$0.44	
CO2 cost	$0.00	
Fuel Cost	$98.91	
Gypsum cost	$0.46	
NH3 cost	$2.93	
NOx cost	$0.21	
SO2 cost	$0.02	
Start Cost	$5.23	
VOM COST	($2.99)	
Production Costs associated with Citrus Delay and CRS Extension	$106.57	Costs

Additional Costs associated with Citrus Delay and CRS Extension	$90.48

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 126
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-16 (140110)

Citrus CC	CPVRR $M	Citrus 1640/1820																
Escalation Rate		May 2018/Nov 2018-April 2053/Oct 2053	Nominal	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
		Summer Capacity not degraded	MW	-	-	-	-	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
		Winter Capacity not degraded	MW	-	-	-	-	-	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
	1,658.39	Generation Capital	$M/yr	-	-	-	-	90.90	205.33	199.04	193.00	187.19	181.59	176.20	170.99	165.88	160.78
	167.09	Fixed O&M	$M/yr	-	-	-	-	4.17	11.41	11.70	11.99	12.29	12.60	12.91	13.23	13.56	13.90
	1,739.63	Gas Reservation Charges	$M/yr	-	-	-	-	59.54	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78
	3,565.11	Fixed Costs	$M/yr	-	-	-	-	154.61	375.51	369.51	363.76	358.25	352.97	347.88	342.99	338.21	333.46
	[illegible]	[illegible]		-													

		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Summer Capacity not degraded	MW	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Winter Capacity not degraded	MW	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
Generation Capital	$M/yr	155.68	150.59	145.49	140.40	135.30	130.20	125.11	120.01	114.92	109.82	105.26	101.77	98.82	95.86
Fixed O&M	$M/yr	14.25	14.61	14.97	15.35	15.73	16.12	16.53	16.94	17.36	17.80	18.24	18.70	19.17	19.65
Gas Reservation Charges	$M/yr	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78
Fixed Costs	$M/yr	328.71	323.97	319.24	314.52	309.81	305.10	300.41	295.73	291.06	286.39	282.28	279.25	276.76	274.29

		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Summer Capacity not degraded	MW	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	-
Winter Capacity not degraded	MW	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	-
Generation Capital	$M/yr	92.91	89.96	87.00	84.05	81.10	78.14	75.19	72.24	69.28	66.33	63.38	34.94	-
Fixed O&M	$M/yr	20.14	20.64	21.16	21.68	22.23	22.78	23.35	23.94	24.53	25.15	25.78	16.51	-
Gas Reservation Charges	$M/yr	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	99.23	-
Fixed Costs	$M/yr	271.82	269.37	266.94	264.51	262.10	259.70	257.32	254.95	252.59	250.25	247.93	150.69	-

Citrus CC	CPVRR $M	Citrus 1640/1820																
Escalation Rate		May 2019/Nov 2019-April 2054/Oct 2054	Nominal	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
		Summer Capacity not degraded	MW	-	-	-	-	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
		Winter Capacity not degraded	MW	-	-	-	-	-	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
	1,596.65	Generation Capital	$M/yr	-	-	-	-	-	93	210	204	198	192	186	181	175	170
	160.87	Fixed O&M	$M/yr	-	-	-	-	-	4	12	12	12	13	13	13	14	14
	1,752.91	Gas Reservation Charges	$M/yr	-	-	-	-	60	159	159	159	159	159	159	159	159	159
	3,510.42	Fixed Costs	$M/yr	-	-	-	-	60	256	381	375	369	363	358	353	348	343
	[illegible]	[illegible]						60	256	374	367	361	355	350	344	339	334
	(61.75)	Differential - Generation Capital	$M/yr	-	-	-	-	(90.90)	(112.16)	11.42	11.02	10.63	10.27	9.94	9.62	9.38	9.24
	(6.22)	Differential - Fixed O&M	$M/yr	-	-	-	-	(4.17)	(7.13)	-	-	-	-	-	-	-	-
	13.28	Differential - Gas Reservation Charges	$M/yr	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(54.69)																

		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Summer Capacity not degraded	MW	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Winter Capacity not degraded	MW	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
Generation Capital	$M/yr	165	160	154	149	144	139	133	128	123	118	113	108	104	101
Fixed O&M	$M/yr	14	15	15	15	16	16	17	17	17	18	18	19	19	20
Gas Reservation Charges	$M/yr	159	159	159	159	159	159	159	159	159	159	159	159	159	159
Fixed Costs	$M/yr	338	333	328	323	318	314	309	304	299	294	290	285	282	280
[illegible]		329	324	319	314	309	304	298	293	288	283	278	274	270	267
Differential - Generation Capital	$M/yr	9.12	8.99	8.86	8.73	8.61	8.48	8.35	8.22	8.10	7.97	7.31	6.12	5.50	5.42
Differential - Fixed O&M	$M/yr	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Differential - Gas Reservation Charges	$M/yr	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Summer Capacity not degraded	MW	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Winter Capacity not degraded	MW	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
Generation Capital	$M/yr	98	95	92	89	86	83	80	77	74	71	68	65	36
Fixed O&M	$M/yr	20	21	21	22	22	23	23	24	25	25	26	26	17
Gas Reservation Charges	$M/yr	159	159	159	159	159	159	159	159	159	159	159	159	99
Fixed Costs	$M/yr	277	275	272	270	267	265	262	260	257	255	253	250	152
[illegible]		265	262	259	256	253	250	248	245	242	239	236	234	141
Differential - Generation Capital	$M/yr	5.35	5.28	5.20	5.13	5.05	4.98	4.91	4.83	4.76	4.69	4.61	30.02	35.81
Differential - Fixed O&M	$M/yr	-	-	-	-	-	-	-	-	-	-	-	9.91	16.93
Differential - Gas Reservation Charges	$M/yr	-	-	-	-	-	-	-	-	-	-	-	59.54	99.23

$M	2014$	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ongoing Capex -Alternate Coal - CRS Retires 2018		0.53	4.08	9.46	1.24					
Ongoing Capex - Alternate Coal - CRS Retires 2019		0.53	4.08	9.46	1.24					
Capital RR - CRS Retires 2018	**16**		-	-	7.50	9.46	2.45	-		
Capital RR - CRS Retires 2019	**17**		-	-	5.44	6.89	6.49	1.71		
Differential - Capital RR	0	-	-	-	(2)	(3)	4	2		
O&M - Annual Budget - CRS Retires 2018	**122**	24	28	45	27	21	11	3	-	
O&M - Annual Budget - CRS Retires 2019	**141**	24	28	45	27	21	21	11	6	
Differential - O&M Capital Budget	19	-	-	-	-	-	11	8	6	
O&M - Alternate Coal - CRS Retires 2018	**5**	-	1	1	2	1	1	0	-	
O&M - Alternate Coal - CRS Retires 2019	**6**	-	1	1	2	1	1	1	0	
Differential - O&M Alternate Coal	1	-	-	-	-	-	0	1	0	
Ongoing Capex - Annual Budget - CRS Retires 2018	**18**	3	2	7	6	3	2	0	-	
Ongoing Capex - Annual Budget - CRS Retires 2019	**21**	3	2	7	6	3	3	2	0	
Differential - Ongoing Capex Annual Budget	2	-	-	-	-	-	2	1	0	
Fixed Costs Revenue Requirement Impact due to CRS Extension	**22**									

Discount Rate 6.46%

3 Yr Avg Except CO2 and Fuel
CO2 & Fuel Escalated Based on 2 Previous Years

TP_1 Duke

Section	Variable	2014 PVRR, K$	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station_RFP201413481	Btm ash cost	37,431	6,287	6,054	3,521	3,480	3,236	3,555	3,501	2,916	3,032	2,851	2,259	2,108
Station_RFP201413481	CaCO3 cost	55,131	7,381	8,041	4,788	4,824	4,573	5,111	5,138	4,361	4,621	4,416	3,559	3,377
Station_RFP201413481	CO2 cost	11,450,691	0	0	407,752	439,067	471,292	525,227	567,327	597,048	656,090	703,526	741,068	800,548
Station_RFP201413481	Fuel Cost	36,025,023	1,809,326	1,888,551	2,107,348	2,184,037	2,264,761	2,374,435	2,442,098	2,542,021	2,670,879	2,759,935	2,852,305	2,960,635
Station_RFP201413481	Gypsum cost	25,844	7,304	8,568	3,838	3,189	2,666	3,162	2,510	1,532	1,461	645	678	950
Station_RFP201413481	NH3 cost	126,059	14,411	12,562	12,472	11,848	11,234	11,941	11,334	10,656	11,319	10,439	8,379	7,977
Station_RFP201413481	NOx cost	3,023	397	311	258	246	237	255	247	225	229	207	192	198
Station_RFP201413481	SO2 cost	95	21	16	10	9	8	9	9	7	8	7	6	4
Station_RFP201413481	Start Cost	359,542	23,448	22,135	25,483	23,888	25,400	26,784	23,558	23,284	23,709	24,237	26,809	30,310
Station_RFP201413481	VOM COST	1,345,413	80,583	84,508	107,670	103,362	102,030	107,044	108,767	108,744	114,677	112,291	105,816	104,247
PVRR	$49,428,252	$49,428,252	1,949,158	[illegible]	2,673,139	2,773,951	2,885,437	3,057,523	3,164,489	3,290,795	3,486,024	3,618,554	3,741,072	3,910,354

Section	Variable	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Station_RFP201413481	Btm ash cost	2,170	2,370	2,437	2,428	2,483	2,489	2,268	2,113	2,276	2,467	2,360	2,525
Station_RFP201413481	CaCO3 cost	3,538	3,921	4,095	4,142	4,303	4,373	4,041	3,820	4,173	4,444	4,179	4,395
Station_RFP201413481	CO2 cost	875,422	967,231	1,061,628	1,153,451	1,227,494	1,314,081	1,385,203	1,463,804	1,572,021	1,690,893	1,803,035	1,938,266
Station_RFP201413481	Fuel Cost	3,086,021	3,231,243	3,395,338	3,537,816	3,676,573	3,828,521	3,952,890	4,075,236	4,213,955	4,356,271	4,517,189	4,669,759
Station_RFP201413481	Gypsum cost	1,368	548	377	370	372	367	328	301	319	339	319	336
Station_RFP201413481	NH3 cost	8,220	8,818	9,165	9,673	10,072	10,388	9,497	8,824	9,210	9,636	9,964	10,376
Station_RFP201413481	NOx cost	205	220	230	230	246	256	241	237	248	259	265	280
Station_RFP201413481	SO2 cost	4	5	5	5	5	5	5	4	5	5	5	5
Station_RFP201413481	Start Cost	29,506	30,634	31,616	32,933	33,075	33,724	37,475	40,275	40,480	42,728	45,577	45,195
Station_RFP201413481	VOM COST	107,876	113,020	118,773	120,740	126,753	131,217	129,223	127,156	130,468	133,849	140,095	144,898
PVRR	$49,428,252	4,114,331	4,358,008	4,623,664	4,861,788	5,081,376	5,325,420	5,521,170	5,721,770	5,973,155	6,240,892	6,522,987	6,816,034

Section	Variable	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Station_RFP201413481	Btm ash cost	2,693	2,608	2,684	2,730	2,701	2,773	2,811	2,749	2,775	2,886	2,836	2,833
Station_RFP201413481	CaCO3 cost	4,605	4,382	4,432	4,428	4,303	4,340	4,322	4,149	4,114	4,201	4,055	4,124
Station_RFP201413481	CO2 cost	2,082,940	2,220,739	2,365,505	2,511,368	2,661,322	2,830,827	3,016,418	3,190,195	3,389,816	3,610,266	3,834,969	4,073,657
Station_RFP201413481	Fuel Cost	4,821,663	4,985,783	5,109,461	5,224,852	5,341,184	5,458,852	5,597,590	5,709,976	5,833,748	5,952,920	6,090,452	6,231,162
Station_RFP201413481	Gypsum cost	352	335	338	338	329	331	330	317	314	321	310	315
Station_RFP201413481	NH3 cost	10,824	11,102	11,484	11,535	11,779	11,983	12,007	12,226	12,555	12,667	12,738	12,653
Station_RFP201413481	NOx cost	291	304	307	319	321	328	338	346	355	366	375	365
Station_RFP201413481	SO2 cost	6	6	6	6	6	6	6	6	6	7	7	6
Station_RFP201413481	Start Cost	46,677	48,675	49,815	49,935	50,524	52,660	51,855	53,722	53,854	57,606	58,218	56,559
Station_RFP201413481	VOM COST	149,129	156,439	159,583	163,503	167,406	171,808	175,973	181,307	185,692	189,657	194,143	189,831
PVRR	$49,428,252	7,119,178	7,430,371	7,703,615	7,969,013	8,239,874	8,533,909	8,861,652	9,154,992	9,483,230	9,830,897	10,198,103	10,571,505

TP_1 Duke, One Year Delay

Section	Variable	2014 PVRR, K$	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station_RFP201413800	Btm ash cost	38,776	7,266	6,852	3,521	3,480	3,236	3,555	3,501	2,916	3,032	2,851	2,259	2,108
Station_RFP201413800	CaCO3 cost	55,575	7,525	8,496	4,788	4,824	4,573	5,111	5,138	4,361	4,621	4,416	3,559	3,377
Station_RFP201413800	CO2 cost	11,450,691	0	0	407,752	439,067	471,292	525,227	567,327	597,048	656,090	703,526	741,068	800,548
Station_RFP201413800	Fuel Cost	36,123,930	1,857,205	1,972,858	2,107,348	2,184,037	2,264,761	2,374,435	2,442,098	2,542,021	2,670,879	2,759,935	2,852,305	2,960,635
Station_RFP201413800	Gypsum cost	26,309	7,446	9,052	3,838	3,189	2,666	3,162	2,510	1,532	1,461	645	678	950
Station_RFP201413800	NH3 cost	128,994	15,858	15,034	12,472	11,848	11,234	11,941	11,334	10,656	11,319	10,439	8,379	7,977
Station_RFP201413800	NOx cost	3,237	554	437	258	246	237	255	247	225	229	207	192	198
Station_RFP201413800	SO2 cost	112	35	25	10	9	8	9	9	7	8	7	6	4
Station_RFP201413800	Start Cost	364,771	25,994	26,576	25,483	23,888	25,400	26,784	23,558	23,284	23,709	24,237	26,809	30,310
Station_RFP201413800	VOM COST	1,342,424	77,268	83,949	107,670	103,362	102,030	107,044	108,767	108,744	114,677	112,291	105,816	104,247
PVRR	$49,534,818	$49,534,818	1,999,151	2,123,279	2,673,139	2,773,951	2,885,437	3,057,523	3,164,489	3,290,795	3,486,024	3,618,554	3,741,072	3,910,354

Section	Variable	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Station_RFP201413800	Btm ash cost	2,170	2,370	2,437	2,428	2,483	2,489	2,268	2,113	2,276	2,467	2,360	2,525
Station_RFP201413800	CaCO3 cost	3,538	3,921	4,095	4,142	4,303	4,373	4,041	3,820	4,173	4,444	4,179	4,395
Station_RFP201413800	CO2 cost	875,422	967,231	1,061,628	1,153,451	1,227,494	1,314,081	1,385,203	1,463,804	1,572,021	1,690,893	1,803,035	1,938,266
Station_RFP201413800	Fuel Cost	3,086,021	3,231,243	3,395,338	3,537,816	3,676,573	3,828,521	3,952,890	4,075,236	4,213,955	4,356,271	4,517,189	4,669,759
Station_RFP201413800	Gypsum cost	1,368	548	377	370	372	367	328	301	319	339	319	336
Station_RFP201413800	NH3 cost	8,220	8,818	9,165	9,673	10,072	10,388	9,497	8,824	9,210	9,636	9,964	10,376
Station_RFP201413800	NOx cost	205	220	230	230	246	256	241	237	248	259	265	280
Station_RFP201413800	SO2 cost	4	5	5	5	5	5	5	4	5	5	5	5
Station_RFP201413800	Start Cost	29,506	30,634	31,616	32,933	33,075	33,724	37,475	40,275	40,480	42,728	45,577	45,195
Station_RFP201413800	VOM COST	107,876	113,020	118,773	120,740	126,753	131,217	129,223	127,156	130,468	133,849	140,095	144,898
PVRR	$49,534,818	4,114,331	4,358,008	4,623,664	4,861,788	5,081,376	5,325,420	5,521,170	5,721,770	5,973,155	6,240,892	6,522,987	6,816,034

Section	Variable	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Station_RFP201413800	Btm ash cost	2,693	2,608	2,684	2,730	2,701	2,773	2,811	2,749	2,775	2,886	2,836	2,833
Station_RFP201413800	CaCO3 cost	4,605	4,382	4,432	4,428	4,303	4,340	4,322	4,149	4,114	4,201	4,055	4,124
Station_RFP201413800	CO2 cost	2,082,940	2,220,739	2,365,505	2,511,368	2,661,322	2,830,827	3,016,418	3,190,195	3,389,816	3,610,266	3,834,969	4,073,657
Station_RFP201413800	Fuel Cost	4,821,663	4,985,783	5,109,461	5,224,852	5,341,184	5,458,852	5,597,590	5,709,976	5,833,748	5,952,920	6,090,452	6,231,162
Station_RFP201413800	Gypsum cost	352	335	338	338	329	331	330	317	314	321	310	315
Station_RFP201413800	NH3 cost	10,824	11,102	11,484	11,535	11,779	11,983	12,007	12,226	12,555	12,667	12,738	12,653
Station_RFP201413800	NOx cost	291	304	307	319	321	328	338	346	355	366	375	365
Station_RFP201413800	SO2 cost	6	6	6	6	6	6	6	6	6	7	7	6
Station_RFP201413800	Start Cost	46,677	48,675	49,815	49,935	50,524	52,660	51,855	53,722	53,854	57,606	58,218	56,559
Station_RFP201413800	VOM COST	149,129	156,439	159,583	163,503	167,406	171,808	175,973	181,307	185,692	189,657	194,143	189,831
PVRR	$49,534,818	7,119,178	7,430,371	7,703,615	7,969,013	8,239,874	8,533,909	8,861,652	9,154,992	9,483,230	9,830,897	10,198,103	10,571,505

	2014 PVRR, K$
Delta Citrus 1 Yr Delay Minus Citrus Base	$106,566

			2014	2015	2016	2017	2018	2019
MW	Citrus 2018							
50	50 MW - Jun-Aug		-	-	-	-	1,088	-
		846						
MW	Citrus 1 YR Delay							
500	500MW - May - Sep		-	-	-	-	-	18,276
150	150MW - May - Sep		-	-	-	-	5,438	-
			-	-	-	-	5,438	18,276
		17,594						
		16,748						

	Cost	Ratio
Debt	3.75%	50.00%
Equity	10.50%	50.00%
Composite Tax Rate	35.26%	
Discount Rate	6.46%	
Insurance Rate	0.05%	
Property Tax Rate	0.91%	
AFUDC Rate	6.464%	
AFUDC Debt (After Tax)	3.75%	
Capitalized Interest Rate	3.750%	
Construction Escalation Rate	0.0%	

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 127
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-12 (140111)

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 128
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-13 (140111)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 129
PARTY: DUKE ENERGY FLORIDA, INC. –
(REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-14
(140111)

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 130
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-15 (140111)

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 131
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-16 (140111)

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 132
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-17 (140111)

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**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 133
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-18 (140111)

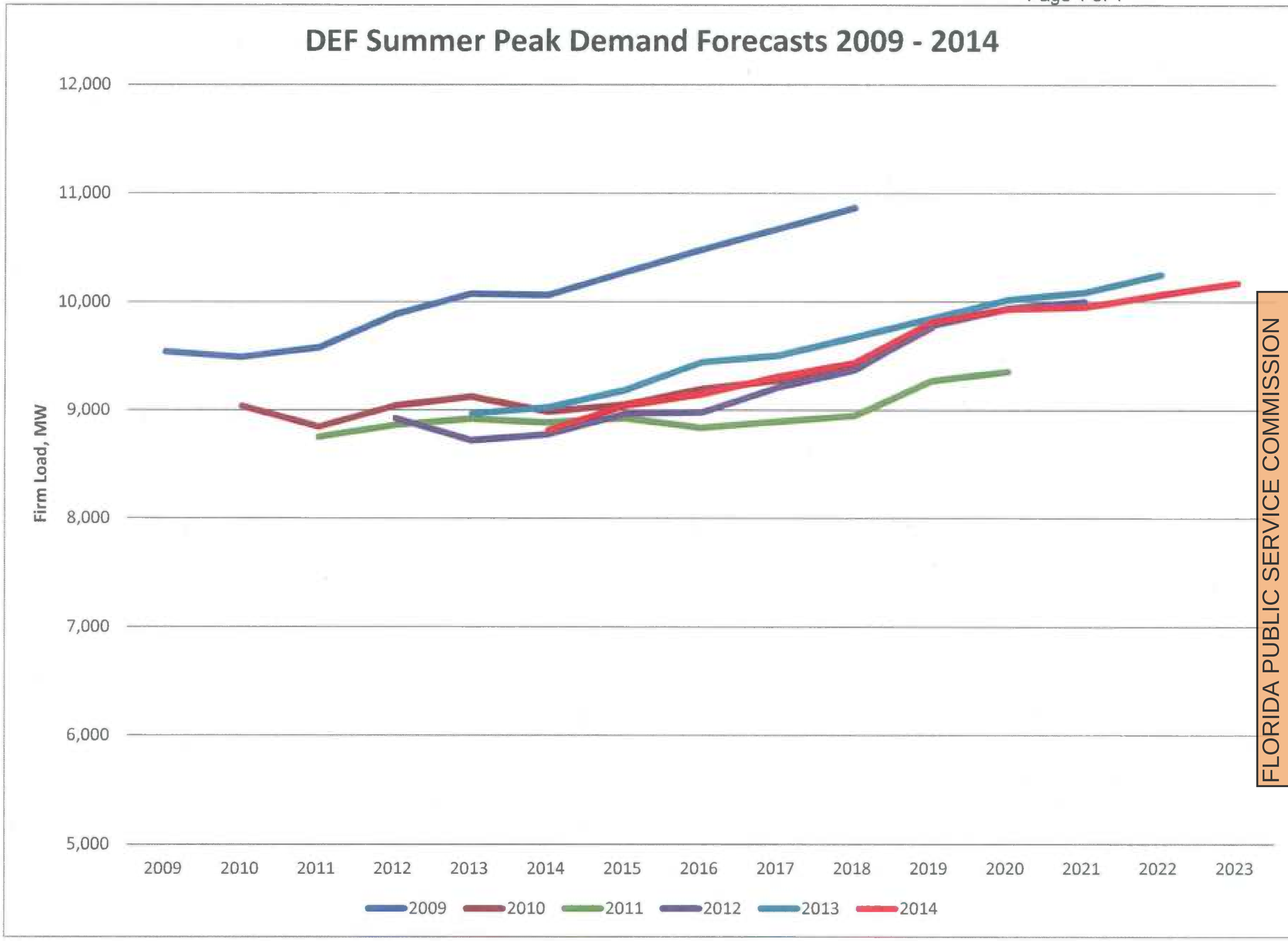
Docket 140111-EI
Duke Energy Florida
Exhibit No. ____ (BMHB-19)
Page 1 of 1

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 134
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch
BMHB-19 (140111)

Docket No. 140111-EI
Duke Energy Florida
Exhibit No. _____ (BMHB-20)
Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 135
PARTY: DUKE ENERGY FLORIDA, INC. – (REBUTTAL)
DESCRIPTION: Benjamin M.H. Borsch BMHB-20 (140111)

EXHIBIT NO. 136

DOCKET NO: 140110-EI

WITNESS: Borsch

PARTY: Duke Energy Florida

DESCRIPTION: Seminole 2013 TYSP Excerpt

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 136
PARTY: Exhibit Number
DESCRIPTION: B. Borsch OPC

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2013 - 2022
(Detail as of December 31, 2012)
April 1, 2013

Submitted To:
State of Florida
Public Service Commission

Seminole Electric
COOPERATIVE, INC.

biomass (wood and paper waste) facility located in Liberty County.

- Landfill Energy Systems – 15 MW (total) of firm capacity from landfill gas-to-energy facilities in Seminole and Brevard Counties. These contracts extend through March 2018.
- Timberline Energy LLC – 1.6 MW of firm capacity from a landfill gas-to-energy facility in Hernando County, Florida. The contract extends through March 2020.
- City of Tampa McKay Bay Waste to Energy Facility - 20 MW of firm waste-to-energy capacity through July 2026.

1.3.2 Purchases from Unit or System Generating Resources

In addition to the renewable resources described above, Seminole's capacity portfolio currently includes power acquired under firm purchased power agreements with the following electric utilities and independent power producers (all ratings are for winter unless otherwise noted):

- Progress Energy Florida (PEF)
  - PEF System Intermediate – up to 625 MW of firm system intermediate and/or combined cycle capacity in 2012, 450 MW in 2013, and 150 MW from January 2014 through December 2020.
  - PEF System Base – 150 MW of firm system base capacity from January 2012 through December 2013, 250 MW from January 2014 through May 2016, and 50 MW from June 2016 through December 2018.
  - PEF Seasonal Peaking – Up to 600 MW of firm summer/winter seasonal system peaking capacity from January 2014 through December 2020.

- PEF System Average – 150 MW of firm system average capacity from January 2014 through May 2016.
- PEF System Combined Cycle – Up to 500 MW of firm system intermediate capacity from June 2016 through December 2024.
- PEF Partial Requirements (PR) – Load following requirements service for Seminole's Member load in the PEF area in excess of Seminole's designated committed capacity. This arrangement provides Seminole some flexibility to modify the amount purchased in future years by modifying its committed capacity. PR service is primarily a peaking-type resource, with quantities varying by month based upon Seminole's committed capacity designations and actual monthly coincident demands. Seminole did not purchase PR capacity in 2012. This agreement terminates on December 31, 2013.

- GenOn Florida, L.P. (GenOn), (formerly RRI Energy Florida, LLC) – 546 MW of firm peaking capacity through May 2014, from GenOn's Osceola combustion turbine units in Osceola County.
- Oleander Power Project, L.P. (a subsidiary of Southern Power Company) – 546 MW of firm peaking capacity, through May 2021, from three combustion turbine units in Brevard County.
- Calpine Construction Finance Company, L.P. (Calpine) – up to 360 MW of firm intermediate capacity, through May 2014, from Calpine's gas-fired Osprey combined cycle plant in Polk County.
- City of Gainesville – Full Requirements service for a specified delivery point of

EXHIBIT NO. 137

DOCKET NO: 140110-EI

WITNESS: Borsch

PARTY: Duke Energy Florida

DESCRIPTION: Seminole Electric Cooperative Contract Excerpts

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 137
PARTY: OPC
DESCRIPTION: Witness B. Borsch

Duke Energy Florida, Inc.
FERC FPA Electric Tariff
Tariffs, Rate Schedules and Service Agreements
Rate Schedule No. 210
Amended January 21, 2009 Agreement with Seminole Electric Cooperative, Inc.
Effective: December 27 2013
Option Code A

AGREEMENT FOR SALE AND PURCHASE

OF

CAPACITY AND ENERGY

BETWEEN

DUKE ENERGY FLORIDA, INC.

AND

SEMINOLE ELECTRIC COOPERATIVE, INC.

DATED AS OF

JANUARY 21, 2009

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY

This Agreement ("Agreement") is made and entered into as of this 21st day of January, 2009 (the "Effective Date") by and between Seminole Electric Cooperative, Inc., a Florida corporation ("Customer"), and Duke Energy Florida, Inc., formerly known as Florida Power Corporation, a Florida corporation, ("Company" or "DEF"). The Company and the Customer are sometimes herein referred to individually as a "Party" and collectively as the "Parties."

WHEREAS

1. The Company is a public utility as defined in the Federal Power Act and sells electric capacity and energy to other utilities for resale;
2. the Customer is a generation and transmission cooperative; and
3. the Parties desire that the Company sell to the Customer and the Customer purchase from the Company electric capacity and energy pursuant to the terms and conditions of this executed Agreement.

NOW THEREFORE

In consideration of the mutual covenants and agreements herein contained, the Parties do hereby mutually agree as follows:

SECTION 1 - DEFINITIONS

For the purposes of this Agreement, the terms defined in this section shall have the following meanings. Except where the context otherwise requires, definitions and other terms expressed in the singular shall include the plural and vice versa.

1.1 "Acceptable Creditworthiness" shall have the meaning set forth in Section 9.7 hereto.

1.2 "Agreement" shall have the meaning set forth in the introductory paragraph hereto.

1.3 "Assignee" shall have the meaning set forth in Section 18.5 hereto.

1.4 "Assigning Party" shall have the meaning set forth in Section 18.5 hereto.

1.5 "Assurance Notice" shall have the meaning set forth in Section 9.9 hereto.

1.6 "Bankrupt" shall mean with respect to any entity that such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors other than the Company's or Customer's mortgagee, as the case may be, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar

1.68 "Total Energy Generated" shall have the meaning set forth in Sections 4.3 and 5.3 hereto, as applicable.

1.69 "Total Fuel Cost" shall have the meaning set forth in Sections 4.3 and 5.3 hereto, as applicable.

1.70 "Transmission Provider" shall mean the business unit within the Company or any successor that provides transmission service to the Customer for the delivery of System Base Capacity, System Average Capacity and Corresponding Energy hereunder.

SECTION 2 - AMOUNTS OF CAPACITY AND ENERGY TO BE SOLD

2.1 System Base Capacity. For the Term, Company agrees to sell to Customer, and Customer agrees to purchase from Company, up to 250 MW of System Base Capacity and, to the extent properly scheduled for delivery pursuant to the terms of this Agreement, the Corresponding Energy.

2.2 System Average Capacity. For the Term, Company agrees to sell to Customer, and Customer agrees to purchase from Company, 150 MW of System Average Capacity and, to the extent properly scheduled for delivery pursuant to the terms of this Agreement, the Corresponding Energy.

SECTION 3 - COMMENCEMENT DATE AND CONDITIONS PRECEDENT

3.1 This Agreement shall become effective as of the Effective Date; provided, however, that the obligations of the Parties to purchase and sell the System Base Capacity, System Average Capacity and Corresponding Energy, as described in Section 2, shall commence on January 1, 2014 (the "Commencement Date"), provided that the conditions precedent set forth in Section 3.2 are satisfied pursuant to the terms thereof.

3.2 The following shall be conditions precedent under this Agreement, and at such time that a condition precedent is satisfied, the affected Party shall notify the other Party in writing within five (5) Business Days that such condition has been satisfied:

(a) This Agreement is approved or accepted for filing by the FERC by June 1, 2009, without modification, suspension, investigation, or other condition unless such modification, suspension, investigation or other condition is agreed upon by the Parties pursuant to Section 3.5; and

(b) This Agreement is approved or accepted by the RUS by June 1, 2009, without modification or condition unless such modification or condition is agreed upon by the Parties pursuant to Section 3.5; and

(c) This Agreement is accepted by the Transmission Provider by June 1, 2009, on terms acceptable to Buyer, in its sole discretion, for the Term as a designated network resource of the Customer. The Parties acknowledge and agree that Company's marketing group does not have any involvement as to the Company's transmission group's determination of whether this Agreement qualifies as a designated network resource.

Parties agree to enter into good faith negotiations in order to determine whether they can reach a mutually satisfactory resolution regarding any such unsatisfied condition(s) precedent. If, after ninety (90) days of attempting to resolve any remaining unsatisfied condition(s) precedent, a mutually satisfactory resolution has not been reached by the Parties, then the Amended Terms shall terminate immediately upon either Party providing written notice of termination to the other Party, and neither Company nor Customer shall have any obligation, duty or liability to the other arising under the Amended Terms under any claim or theory whatsoever.

(vi) If FERC rejects the Amended Terms or fails to act by January 31, 2012, or if the Transmission Provider rejects the Amended Terms as a designated network resource or fails to act by December 31, 2011, then the Amended Terms shall terminate immediately upon the affected Party (which is Company or Customer in the case of action or inaction by FERC and is Customer in the case of action or inaction by the Transmission Provider) providing written notice of termination to the other Party, and neither Company nor Customer shall have any obligation, duty or liability to the other arising under the Amended Terms under any claim or theory whatsoever.

SECTION 4 - SYSTEM BASE CAPACITY

4.1 Term. For the period January 1, 2014, through May 31, 2016, Company will sell to Customer 250 MW of System Base Capacity and Corresponding Energy as provided herein. For the period June 1, 2016, through December 31, 2018, Company will sell to Customer 50 MW of System Base Capacity and Corresponding Energy as provided herein. The period from January 1, 2014 through December 31, 2018 shall be identified as the "Term" for System Base Capacity purchases.

4.2 Dispatch. System Base Capacity and Corresponding Energy will be given a dispatch and commitment priority equivalent to that of Company's Firm Native Load, and the service will be as firm as service to the Company's Firm Native Load. Customer may use said System Base Capacity and Corresponding Energy for any purpose, subject only to Customer's scheduling requirements, as defined in Section 6, below.

4.3 Rates and Charges. The charges for System Base Capacity and Corresponding Energy shall consist of the following:

(a) Monthly Capacity Charge – For each month in 2014, the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 250,000 kW and $20.00 per kW-month (or $5,000,000). For each month in 2015, the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 250,000 kW and $22.00 per kW-month (or $5,500,000). For each month from January 2016 through May 2016, the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 250,000 kW and $24.00 per kW-month (or $6,000,000). For each month from June 2016 through December

SECTION 5 - SYSTEM AVERAGE CAPACITY

5.1 Term. For the period January 1, 2014, through May 31, 2016 (the "Term"), Company will sell to Customer 150 MW of System Average Capacity and Corresponding Energy as provided herein.

5.2 Dispatch. System Average Capacity and Corresponding Energy will be given a dispatch and commitment priority equivalent to that of Company's Firm Native Load and the service will be as firm as service to the Company's Firm Native Load. Customer may use said System Average Capacity and Corresponding Energy for any purpose, subject only to Customer's scheduling requirements, as defined in Section 6, below.

5.3 Rates and Charges. The charges for System Average Capacity and Corresponding Energy shall consist of the following:

(a) Monthly Capacity Charge – For each month in 2014, the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 150,000 kW and $16.00 per kW-month (or $2,400,000). For each month in 2015, the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 150,000 kW and $17.00 per kW-month (or $2,550,000). For each month in 2016 (through May), the Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 150,000 kW and $20.00 per kW-month (or $3,000,000).

(b) Monthly Non-Fuel Energy Charge - The Customer shall pay to the Company a Monthly Non-Fuel Energy Charge equal to the product of the Corresponding Energy delivered during the Billing Month and $4.50 per MWh. The Monthly Non-Fuel Energy Charge shall be fixed for the Term, except as provided in Section 15.

(c) Monthly Fuel Charge - The Customer shall pay to the Company a monthly fuel charge (the "Monthly Fuel Charge") equal to the product of (i) the Fuel Rate (as defined below), and (ii) the Corresponding Energy delivered during the Billing Month (as set forth below). The Fuel Rate shall be determined in the following manner:

The "Fuel Rate" ($/MWh) = Total Fuel Cost divided by Total Energy Generated.

(i)"Total Fuel Cost" ($) is defined as the Company's fuel costs for all of the Company's System Average Capacity Resources (defined in Section 1.63 as the capacity from the Company's system generating resources and power purchase agreements, excluding Company's interchange sales, company use and stratified sales).

(ii) "Total Energy Generated" (MWh) is defined as the actual net generation of all System Average Capacity Resources for the relevant Billing Month, as adjusted to reflect a loss factor associated with losses from the applicable generator busbar(s) to the Delivery Point

AGREEMENT FOR SALE AND PURCHASE

OF

CAPACITY AND ENERGY

BETWEEN

DUKE ENERGY FLORIDA, INC.

AND

SEMINOLE ELECTRIC COOPERATIVE, INC.

DATED AS OF

September 22, 2006

AGREEMENT FOR SALE AND PURCHASE
OF CAPACITY AND ENERGY

This Agreement ("Agreement") is made and entered into as of this 22nd day of September, 2006 by and between Seminole Electric Cooperative, Inc., a Florida corporation ("Customer"), and Duke Energy Florida, Inc., formerly known as Florida Power Corporation, a Florida corporation, ("Company"). The Company and the Customer are sometimes herein referred to individually as a "Party" and collectively as the "Parties."

WHEREAS

1. The Company is a public utility as defined in the Federal Power Act and sells electric capacity and energy to other utilities for resale;
2. the Customer is a generation and transmission cooperative; and
3. the Parties desire that the Company sell to the Customer and the Customer purchase from the Company electric capacity and energy pursuant to the terms and conditions of this executed Agreement.

NOW THEREFORE

In consideration of the mutual covenants and agreements herein contained, the Parties do hereby mutually agree as follows:

SECTION 1 -DEFINITIONS

For the purposes of this Agreement, the terms defined in this section shall have the following meanings. Except where the context otherwise requires, definitions and other terms expressed in the singular shall include the plural and vice versa.

1.1 "Acceptable Creditworthiness" shall have the meaning set forth in Section 9.7 hereto.

1.2 "Agreement" shall have the meaning set forth in the introductory paragraph hereto.

1.3 "Assigning Party" shall have the meaning set forth in Section 18.5 hereto.

1.4 "Assurance Notice" shall have the meaning set forth in Section 9.9 hereto.

1.5 "Billing Month" shall mean a calendar month billing cycle for invoicing.

1.6 "Binding Arbitration Notice" shall have the meaning set forth in Section 18.3 hereto.

1.7 "Business Day" shall mean any day except Saturdays, Sundays, and Federal Reserve Bank holidays.

1.8 "Change in Environmental Law" shall have the meaning set forth in Section 15.1 hereto.

SECTION 2 - AMOUNTS OF CAPACITY AND ENERGY TO BE SOLD

2.1 For the Term, Company agrees to sell to Customer, and Customer agrees to purchase from Company, the following capacity and Corresponding Energy:

(a) System Intermediate Capacity – 150 MW

(b) Seasonal System Peaking Capacity – Up to 600 MW

SECTION 3 - EFFECTIVE DATE AND CONDITIONS PRECEDENT

3.1 This Agreement shall become effective upon execution and delivery by the Parties ("Effective Date"), provided that obligations of the Parties to purchase and sell capacity and Corresponding Energy shall commence on January 1, 2014, provided that the conditions precedent set forth in Section 3.2 are satisfied (the "Commencement Date").

3.2 The following shall be conditions precedent under this Agreement, and at such time that a condition precedent is satisfied, the affected Party shall notify the other Party in writing within five (5) Business Days that such condition has been satisfied:

(a) This Agreement is approved or accepted for filing by the FERC by December 31, 2007, without modification, suspension, investigation, or other condition unless such modification, suspension, investigation or other condition is agreed upon by the Parties pursuant to Section 3.5; and

(b) This Agreement is approved or accepted by the RUS by December 31, 2007, without modification or condition unless such modification, or condition is agreed upon by the Parties pursuant to Section 3.5; and

(c) This Agreement is unconditionally accepted by the Transmission Provider for its Term as a designated network resource of the Customer by December 31, 2007. The Company's marketing group does not have any involvement as to the Company's transmission group's determination of whether this Agreement qualifies as a designated network resource.

3.3 Company will file this Agreement, together with supporting documents, with FERC pursuant to the requirements of the Federal Power Act no later than March 31, 2007. Thereafter, Company shall diligently pursue acceptance of this Agreement by FERC. Company shall keep Customer informed of its efforts in such regard. If requested by Company, Customer shall undertake commercially reasonable efforts to cooperate with and assist Company in Company's efforts to pursue acceptance of this Agreement by FERC and request FERC action on this filing and, upon Company's request, shall make a timely submittal at FERC affirmatively supporting the acceptance of this Agreement by FERC without modification, suspension, investigation, or other condition.

3.4 Customer shall take appropriate steps to submit this Agreement, together with supporting documents, to the RUS no later than December 15, 2006. Thereafter, Customer shall diligently pursue approval of this Agreement by the RUS and shall keep Company informed of the progress in such regard. If requested by Customer, Company shall to the other Party, and neither Company nor Customer shall have any obligation, duty or liability to the other arising under the Amended Terms under any claim or theory whatsoever.

SECTION 4 - SYSTEM INTERMEDIATE CAPACITY

4.1 Term. For the period January 1, 2014, through December 31, 2020, Company will sell to Customer 150 MW of System Intermediate Capacity and Corresponding Energy as provided herein.

4.2 Dispatch. System Intermediate Capacity and Corresponding Energy will be given a dispatch and commitment priority equivalent to that of Company's Firm Native Load and the service will be as firm as service to the Company's Firm Native Load. Customer may use said System Intermediate Capacity and Corresponding Energy for any purpose, subject only to Customer's scheduling rights, as defined in Section 6, below.

4.3 Rates and Charges. The charges for System Intermediate Capacity and Corresponding Energy shall include the following:

(a) Monthly Capacity Charge – The Customer shall pay to the Company a Monthly Capacity Charge equal to the product of 150,000 kW and the Monthly Capacity Charge Rate shown in Table 4.3.

(b) Monthly Non-Fuel Energy Charge - The Customer shall pay to the Company a Monthly Non-Fuel Energy Charge equal to the product of the Corresponding Energy delivered during the Billing Month and the Monthly Non-Fuel Energy Charge Rate shown in Table 4.3.

Table 4.3
Rates for System Intermediate Capacity
and Non-Fuel Energy

Year	Monthly Capacity Charge Rate $/kW-month	Monthly Non-Fuel Energy Charge Rate $/MWh
2014	7.98	4.68
2015	7.98	4.77
2016	7.98	4.87
2017	7.98	4.97
2018	7.98	5.07
2019	7.98	5.17
2020	7.98	5.27

(c) Monthly Fuel Charge - The Customer shall pay to the Company a monthly fuel charge (the "Monthly Fuel Charge") equal to the product of (i) the Fuel Rate (as defined below), and (ii) the Corresponding Energy delivered during the Billing Month. The Fuel Rate shall be determined in the following manner:

The "Fuel Rate" ($/MWh) = Total Fuel Cost divided by Total Energy Generated.

(i) "Total Fuel Cost" ($) is defined as the sum of the fuel costs for all System Intermediate Capacity Resources plus the fuel costs for Interchange Purchases assigned to the System Intermediate Capacity Resource stratification as provided in Section 8.1(b) for the Billing Month. Exhibit 3 of this Agreement lists the fuel cost components to be used in the Total Fuel Cost calculation and is derived from costs permitted by the Commission for cost recovery that are associated with providing fuel for the System Intermediate Capacity Resources and delivery of purchased power and Interchange Purchases assigned to the System Intermediate Capacity Resource stratification. The Total Fuel Cost shall be limited to only those costs that the Commission allows for recovery by Company upon its acceptance of this Agreement and may not include any costs that are duplicative of those costs already recovered through the Monthly Capacity Charges or the Monthly Non-Fuel Energy Charges hereunder.

(ii) "Total Energy Generated" (MWh) is defined as the actual net generation of all System Intermediate Capacity Resources plus Interchange Purchases that are stratified in accordance with Section 8.1(b) as System Intermediate Capacity Resources for the Billing Month.

SECTION 5 - SEASONAL SYSTEM PEAKING CAPACITY

5.1 Term.

(a) Winter Season. For the period January 1, 2014, through March 31, 2014, during the three calendar months of January, February and March, Company will sell to Customer 100 MW of Seasonal System Peaking Capacity and Corresponding Energy as provided herein. For the period December 1, 2014, through December 31, 2020, during the four calendar months of January, February, March and December of each year, Company will sell to Customer 600 MW of Seasonal System Peaking Capacity and Corresponding Energy as provided herein.

(b) Summer Season. For the period June 1, 2017, through September 30, 2020, during the four calendar months of June, July, August and September of each year, Company will sell to Customer 100 MW of Seasonal System Peaking Capacity and Corresponding Energy as provided herein.

5.2 Dispatch. Seasonal System Peaking Capacity and Corresponding Energy will be given a dispatch and commitment priority equivalent to that of Company's Firm Native Load and the service will be as firm as service to the Company's Firm Native Load. Customer may use said Seasonal System Peaking Capacity and Corresponding Energy for any purpose, subject only to Customer's scheduling rights, as defined in Section 6, below.

18.16 Survival of Provisions. Expiration or termination of the Agreement shall be without prejudice to any rights or claims of either Party against the other Party and shall not relieve either Party of any obligations which by their nature survive the expiration or termination of the Agreement, including, but not limited to, warranty, indemnification, limitation of liability and the obligation to pay amounts due for service rendered prior to termination. Such obligations shall continue in full force and effect subsequent to and regardless of the expiration or termination of the Agreement and until they are fully satisfied or by their nature expired.

18.17 Notice: Any notice or request made to or by either Party regarding this Agreement shall be made to:

Company:

Duke Energy Florida, Inc.
100 Central Avenue
MAC-BT9G
St. Petersburg, Florida 33701
Attention: Director, Origination, Account Management & Cogeneration – DEF

Customer:

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618
Attention: Director, Pricing and Bulk Power Contracts

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized officers, and copies delivered to each Party, as of the day and year first stated above.

ATTEST:

By:________________________

FLORIDA POWER CORPORATION:
(now DUKE ENERGY FLORIDA, INC.)

By: *_/s/ Robert F. Caldwell_*
Robert F. Caldwell
Vice President,
Regulated Commercial Operations

ATTEST:

By:________________________

SEMINOLE ELECTRIC COOPERATIVE, INC.

By: *_/s/ Richard J. Midulla_*
Richard J. Midulla
Executive Vice President
and General Manager

Execution Copy

FIRST AMENDMENT TO AGREEMENT FOR SALE AND PURCHASE OF SYSTEM COMBINED CYCLE CAPACITY AND ENERGY

BETWEEN

FLORIDA POWER CORPORATION,

DOING BUSINESS AS

PROGRESS ENERGY FLORIDA,

AND

SEMINOLE ELECTRIC COOPERATIVE, INC.

FIRST AMENDMENT TO AGREEMENT FOR SALE AND PURCHASE OF SYSTEM COMBINED CYCLE CAPACITY AND ENERGY BETWEEN FLORIDA POWER CORPORATION, DOING BUSINESS AS PROGRESS ENERGY FLORIDA AND SEMINOLE ELECTRIC COOPERATIVE, INC.

This First Amendment ("First Amendment") to the Agreement for Sale and Purchase of Capacity and Energy between Florida Power Corporation, doing business as Progress Energy Florida, and Seminole Electric Cooperative, Inc. dated as of December 18, 2009, as amended by letter agreements ("Agreement") is entered into by and between Florida Power Corporation, doing business as Progress Energy Florida ("Company") and Seminole Electric Cooperative, Inc. ("Customer") this 29th day of September, 2011 ("Effective Date"). Company and Customer may herein be referred to individually as a "Party" and collectively as the "Parties."

WITNESSETH

Now, therefore, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable considerations to each of the Parties hereto, the Parties do hereby mutually agree as follows:

1. Except as to matters expressly defined in this First Amendment, the definitions used in the Agreement shall apply to this First Amendment.
2. The Parties agree to amend Sections 2.1, 2.3, 5.1, and 5.3 of the Agreement as shown in the mark-up below:

SECTION 2 - AMOUNTS OF CAPACITY AND ENERGY TO BE SOLD

2.1 System Combined Cycle Capacity and Corresponding Energy. For the Term, Company agrees to sell to Customer, and Customer agrees to purchase from Company, System Combined Cycle Capacity in the amount of 200 MW during the period from June 1, 2016, through December 31, 2018, and 250 MW during the period from January~~une~~ 1, 2019~~6~~, through May 31, 2019 (collectively, the period from June 1, 2016 through May 31, 2019 shall be referred to as "Period 1"), in the amount of 500 MW during the period from June 1, 2019, through December 31, 2022 ("Period 2"), and in the amount of 200 MW during the period from January 1, 2023 through December 31. 2024 ("Period 3"), and, to the extent properly scheduled for delivery pursuant to the terms of this Agreement, the Corresponding Energy. The capacity MW amounts in Period 1, Period 2 and Period 3 may be reduced and/or increased by the Customer as set forth in Section

2. The "Contract Capacity Amount" shall be defined for Period 1, Period 2 and Period 3, respectively, as the capacity MW amounts in Period 1, Period 2 and Period 3 as such amounts may be adjusted to reflect any reductions and/or increases in the capacity MW amounts by the Customer consistent with Section 2.

2.3 Customer Opportunities To Increase the Contract Capacity Amount in Period 1 and Period 2 Up to a Maximum Total of 500 MW.

(a) Once every calendar year, on or before December 15th, with written notice to Company of not less than twenty-four (24) months, Customer shall have the opportunity to increase the Contract Capacity Amount in Period 1 up to a maximum amount of 500 MW. The elected increase shall be made only in an amount that is in 25 MW increments and effective only as of a particular January 1 during Period 1 (or June 1 if Customer elects to increase the Contract Capacity Amount in 2016), and the elected increase shall be applicable to the remaining time period in Period 1. Customer's election under this Section 2.3(a) does not impact the Customer's ability to reduce its purchase under Section 2.2(a). As a result of Customer's cumulative elections under Sections 2.2(a) and/or 2.3(a), the Contract Capacity Amount in Period 1 shall be no less than 100 MW and no more than 500 MW.

(b) In the event Customer has elected under Section 2.2(b) to reduce the 500 MW Contract Capacity Amount in Period 2, then once every calendar year, on or before December 15th, with written notice to Company of not less than twenty-four (24) months, Customer shall have the opportunity to increase the Contract Capacity Amount in Period 2 up to a maximum amount of 500 MW. The elected increase shall be made only in an amount that is in 25 MW increments and effective only as of a particular January 1 during Period 2, and the elected increase shall be applicable to the remaining time period in Period 2. As a result of Customer's cumulative elections under Sections 2.2(b) and/or 2.3(b), the Contract Capacity Amount in Period 2 shall be no less than 200 MW and no more than 500 MW.

(c) Notwithstanding Sections 2.3 (a) and (b) above, in no event shall the Customer be able to increase the Contract Capacity Amount above 450 MW during the period from June 1, 2016, through December 31, 2018.

SECTION 5 – CUSTOMER GAS OPTION

5.1 Description of Gas Option. Subject to the provisions of Section 5.5 below, Customer shall have the option to deliver to Company up to 30,000 Dth/day of natural gas that is required to generate energy up to the amount of Corresponding Energy plus losses using the applicable OTL Loss Factor ("Gas Option"). Customer will have the ability to utilize the Gas Option for a maximum of ~~forty-eight (48)~~ eighty-eight (88) days during a calendar year. For any partial years during the Term, the Customer's Gas Option Days shall be prorated according to the number of months in the year (e.g., in 2016, Customer shall have ~~twenty-eight (28)~~ fifty-one (51) days). Customer may only use the Gas Option on a day ahead basis (e.g., no intraday or month-ahead notifications will be accepted by Company), and Customer will notify Company of its election to use its Gas Option and the gas quantity to be supplied to Company at the Scheduling Deadline along with its Schedule for Energy, as described in Section 6 below. Additionally, use of the Gas Option by Customer shall be subject to physical pipeline constraints (e.g., Customer may not elect to use the Gas Option if FGT declares a Force Majeure (as defined in the FGT tariff) affecting deliveries to the Hines Energy Center or FGT cannot otherwise accommodate additional gas at the Hines Energy Center gas delivery point).

5.3 Communication of Gas Option. Company and Customer will coordinate their daily activities regarding Customer's use of its Gas Option according to the following provisions:

(a) On or before FGT's timely cycle scheduling deadline for day ahead, Customer will provide Company notification of which natural gas transportation contracts (and their respective quantities) have been used to schedule gas on FGT to be delivered to the Hines Energy Center, which such scheduled quantities for delivery shall not exceed the quantity specified in Section 5.1 above.

(b) Gas Option Interruption. Customer will provide timely notification to Company of any expected cuts to its scheduled deliveries under the Gas Option, and any such day in which such cuts are actualized (a "Gas Option Interruption") will count against the ~~forty-eight (48)~~ eighty eight (88) days of Gas Option flexibility provided to Customer in Section 5.1 above. If Customer is not able to restore its expected deliveries by 10:00 a.m. EPT (i.e., the beginning of the next Gas Day), then Company will quote a price for intraday fuel delivery and Customer will have the option to (i) pay any Incremental Costs reasonably determined by Company to be attributable to meeting Customer's Schedule for Energy or (ii) reduce its Schedule for Energy. If Customer has not reduced its Schedule for Energy in response to any gas cuts, any FGT overage penalties charged to Company as a result of Customer not supplying natural gas under the Gas Option shall be treated as an Incremental Cost and shall be reimbursed by Customer. For the avoidance of doubt, Company's obligation to deliver energy to Customer under this Agreement is not affected if Customer fails to deliver natural gas to Company under the Gas Option.

3. This First Amendment shall become effective as of the Effective Date; provided, however, that the rights and obligations of the Parties under amended Sections 2.1, 2.3, 5.1 and 5.3 of the Agreement shall not become effective until the conditions precedent set forth in item 4 below are satisfied or waived.

4. The following shall be conditions precedent under this First Amendment, and at such time that a condition precedent is satisfied, the affected Party shall notify the other Party in writing within five (5) Business Days that such condition has been satisfied:

a. This Agreement is approved or accepted for filing by the Federal Energy Regulatory Commission ("FERC") by January 31, 2012, without modification, suspension, investigation, or other condition unless such modification, suspension, investigation or other condition is agreed upon by the Parties pursuant to item 4(e) hereunder.

b. The effectiveness of item 3 of this First Amendment also shall be expressly contingent on the FERC approving or accepting the Other Agreements, as defined below, for filing by the FERC by January 31, 2012, without modification, suspension, investigation, or other condition unless such modification, suspension, investigation or other condition is agreed upon by the Parties as set forth in the Other Agreements. The Other Agreements are the following agreements between the Parties, as amended on September 29, 2011: (1) the October 12, 1995 Agreement; (2) the September 22, 2006 Agreement; (3) the February 9, 2004 Agreement; and (4) the January 21, 2009 Agreement.

c. The reduction to the purchase amount of System Combined Cycle Capacity and Corresponding Energy hereunder is accepted by the Transmission Provider by December 31, 2011, on terms acceptable to the Customer, in its sole discretion, for the applicable portion of the Term. The Parties acknowledge and agree that Company's marketing group does not have any involvement as to the Company's transmission group's approval of Customer's request under this First Amendment.

d. Company will file this First Amendment, together with supporting documents, with FERC pursuant to the requirements of the Federal Power Act no later than October 21, 2011. Thereafter, Company shall diligently pursue acceptance of this First Amendment by FERC. Company shall keep Customer informed of its efforts in such regard. If requested by Company, Customer shall undertake commercially reasonable efforts to cooperate with and assist Company in Company's efforts to pursue acceptance of this First Amendment by FERC and request FERC action on this filing and, upon Company's request, shall make a timely submittal at FERC affirmatively supporting the acceptance of this First Amendment by FERC without modification, suspension, investigation, or other condition.

e. If FERC conditionally accepts the First Amendment subject to modification or other condition prior to January 31, 2012, or if the Transmission Provider conditionally accepts the Customer's reduced designated network resource request prior to December 31, 2011 (for example, the Transmission Provider seeks to levy additional costs upon Customer), then the Parties agree to enter into good faith negotiations in order to determine whether they can reach a mutually satisfactory resolution regarding any such unsatisfied condition(s) precedent. If, after ninety (90) days of attempting to resolve any remaining unsatisfied condition(s) precedent, a mutually satisfactory resolution has not been reached by the Parties, then this First Amendment shall terminate immediately upon either Party providing written notice of termination to the other Party, and neither Company nor Customer shall have any obligation, duty or liability to the other arising under this First Amendment under any claim or theory whatsoever.

f. If FERC rejects the First Amendment or fails to act by January 31, 2012, or if the Transmission Provider does not accept the Customer's reduced designated network resource or fails to act by December 31, 2011, then this First Amendment shall terminate immediately upon the affected Party (which is Company or Customer in the case of action or inaction by FERC and is Customer in the case of action or inaction by the Transmission Provider) providing written notice of termination to the other Party, and neither Company nor Customer shall have any obligation, duty or liability to the other arising under this First Amendment under any claim or theory whatsoever.

5. Except to the extent amended hereby as set forth above, all other terms and provisions of the Agreement shall remain unchanged and are in full force and effect.

6. Each Party represents and warrants to the other that: (i) each has the capacity, authority and power to execute, deliver, and perform under this First Amendment; (ii) this First Amendment constitutes legal, valid and binding obligations enforceable against it; (iii) each person who executes this First Amendment on behalf of each Party warrants to having full and complete authority to do so; (iv) each Party is acting on its own behalf, has made its own independent decision to enter into this First Amendment, has performed its own independent due diligence, is not relying upon the recommendations of any other party, and is capable of understanding, understands, and accepts the provisions of this First Amendment; (v) each Party has completely read, fully understands, and voluntarily accepts every provision of this First Amendment; and (vi) each Party agrees that neither Party shall have any provision hereof construed against such Party by reason of such Party drafting any provision of this document, nor is any provision of this First Amendment intended to modify or otherwise clarify the intent of any provision of the Agreement, except to the extent expressly set forth herein.

7. This First Amendment may be executed in one or more counterparts, and each executed counterpart constituting an original but all together only one executed First Amendment.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Parties have caused this First Amendment to be executed by their respective authorized officials.

FLORIDA POWER CORPORATION

By: ____________________

Name: Robert F. Caldwell

SEMINOLE ELECTRIC COOPERATIVE, INC

By: ____________________

Legal Review
RAM

Name: TIMOTHY S. WOODBURY

EXHIBIT NO. 138

DOCKET NO: 140110-EI

WITNESS: Borsch

PARTY: Duke Energy Florida

DESCRIPTION: Citrus Delay w/ Osprey Scenario

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 138
PARTY: OPC
DESCRIPTION: B. Borsch

Duke Energy Florida, Inc Load and Resource Balance (Per the 2014 Ten Year Site Plan Dated April 2014 Plus Additional Hines Chiller)

Line	Description	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	TOTAL Summer Demand		10,359	10,631	10,775	10,998	11,169	11,620	11,795	11,841	11,985	12,118
2	Subtotal Load Reduction Measures		1547	1590	1626	1692	1729	1807	1859	1890	1917	1944
3	Net Firm Demand (Line 1 - Line 2)		8,812	9,041	9,149	9,306	9,440	9,813	9,936	9,951	10,068	10,174
4	Total DEF Initial Installed Capacity (Jan 1, 2014)		9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141
	Retirements and Additions	Unit										
5	ANCLOTE	1	17	17	17	17	17	17	17	17	17	17
6	ANCLOTE	2		20	20	20	20	20	20	20	20	20
7	TURNER	3		(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
8	CRYSTAL RIVER	1			(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
9	CRYSTAL RIVER	2			(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
10	TURNER	P 1-2			(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
11	AVON PARK	P 1-2			(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
12	RIO PINAR	P1			(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
13	SUWANNEE RIVER	P 4-5			316	316	316	316	316	316	316	316
14	HINES	1 - 4				220	220	220	220	220	220	220
15	CRYSTAL RIVER	1					(320)	(320)	(320)	(320)	(320)	(320)
16	CRYSTAL RIVER	2					(420)	(420)	(420)	(420)	(420)	(420)
17	SUWANNEE RIVER	1-3					(131)	(131)	(131)	(131)	(131)	(131)
18	CITRUS	1					820	1640	1640	1640	1640	1640
19	HIGGINS	P 1-4							(105)	(105)	(105)	(105)
20	UNKNOWN	1								793	793	793
21	Subtotal Retirements and Additions		17	(16)	91	311	260	1080	975	1768	1768	1768
22	Subtotal DEF Initial Installed Capacity		9,158	9,125	9,232	9,452	9,401	10,221	10,116	10,909	10,909	10,909
23	less Southern Co Sale		(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)
24	Subtotal Available DEF Installed Capacity		9,015	8,982	9,089	9,309	9,258	10,078	9,973	10,766	10,766	10,766
25	Firm Capacity Imports		1,831	1,831	1,873	1,873	1,923	1,873	1,873	1,448	1,448	1,448
26	QF		177	177	177	177	177	177	177	177	177	177
27	Total Available Summer Capacity		11,023	10,990	11,139	11,359	11,358	12,128	12,023	12,391	12,391	12,391
28	Reserve Margin Before Maintenance		2,211	1,949	1,990	2,053	1,918	2,315	2,087	2,440	2,323	2,217
29	Reserve Margin as % of Net Firm Summer Demand		25.1%	21.6%	21.8%	22.1%	20.3%	23.6%	21.0%	24.5%	23.1%	21.8%

Duke Energy Florida, Inc Load and Resource Balance Critus Slipped 1 Year

Line	Description	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	TOTAL Summer Demand		10,359	10,631	10,775	10,998	11,169	11,620	11,795	11,841	11,985	12,118
2	a. WHOLESALE		804	806	658	587	587	837	837	737	738	738
3	b. RETAIL		9,555	9,825	10,117	10,411	10,582	10,783	10,958	11,104	11,247	11,380
4	Subtotal Load Reduction Measures		1547	1590	1626	1692	1729	1807	1859	1890	1917	1944
5	Net Firm Demand (Line 1 - Line 2)		8,812	9,041	9,149	9,306	9,440	9,813	9,936	9,951	10,068	10,174
6	Total DEF Initial Installed Capacity (Jan 1, 2014)		9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141	9,141
	Retirements and Additions	Unit										
7	ANCLOTE	1	17	17	17	17	17	17	17	17	17	17
8	ANCLOTE	2		20	20	20	20	20	20	20	20	20
9	TURNER	3		(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
10	CRYSTAL RIVER	1			(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
11	CRYSTAL RIVER	2			(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
12	TURNER	P 1-2			(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
13	AVON PARK	P 1-2			(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
14	RIO PINAR	P1			(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
15	**OSPREY**	**CC**			**515**	**515**	**515**	**515**	**515**	**515**	**515**	**515**
16	HINES	1 - 4				220	220	220	220	220	220	220
17	**CRYSTAL RIVER**	**1**					**0**	**0**	**(320)**	**(320)**	**(320)**	**(320)**
18	**CRYSTAL RIVER**	**2**					**0**	**(420)**	**(420)**	**(420)**	**(420)**	**(420)**
19	SUWANNEE RIVER	1-3						(131)	(131)	(131)	(131)	(131)
20	**CITRUS**	**1**					**0**	**820**	**1640**	**1640**	**1640**	**1640**
21	HIGGINS	P 1-4							(105)	(105)	(105)	(105)
22	UNKNOWN	1								793	793	793
23	Subtotal Retirements and Additions		17	(16)	290	510	510	779	1174	1967	1967	1967
24	Subtotal DEF Initial Installed Capacity		9,158	9,125	9,431	9,651	9,651	9,920	10,315	11,108	11,108	11,108
25	less Southern Co Sale		(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)
26	Subtotal Available DEF Installed Capacity		9,015	8,982	9,288	9,508	9,508	9,777	10,172	10,965	10,965	10,965
27	Firm Capacity Imports		1,831	1,831	1,873	1,873	1,923	1,873	1,873	1,448	1,448	1,448
28	QF		177	177	177	177	177	177	177	177	177	177
29	Total Available Summer Capacity		11,023	10,990	11,338	11,558	11,608	11,827	12,222	12,590	12,590	12,590
30	Reserve Margin Before Maintenance		2,211	1,949	2,189	2,252	2,168	2,014	2,286	2,639	2,522	2,416
31	Reserve Margin as % of Net Firm Summer Demand		25.1%	21.6%	23.9%	24.2%	23.0%	20.5%	23.0%	26.5%	25.0%	23.7%

EXHIBIT NO. 139

DOCKET NO: 140110-EI & 140111-EI

WITNESS: Borsch

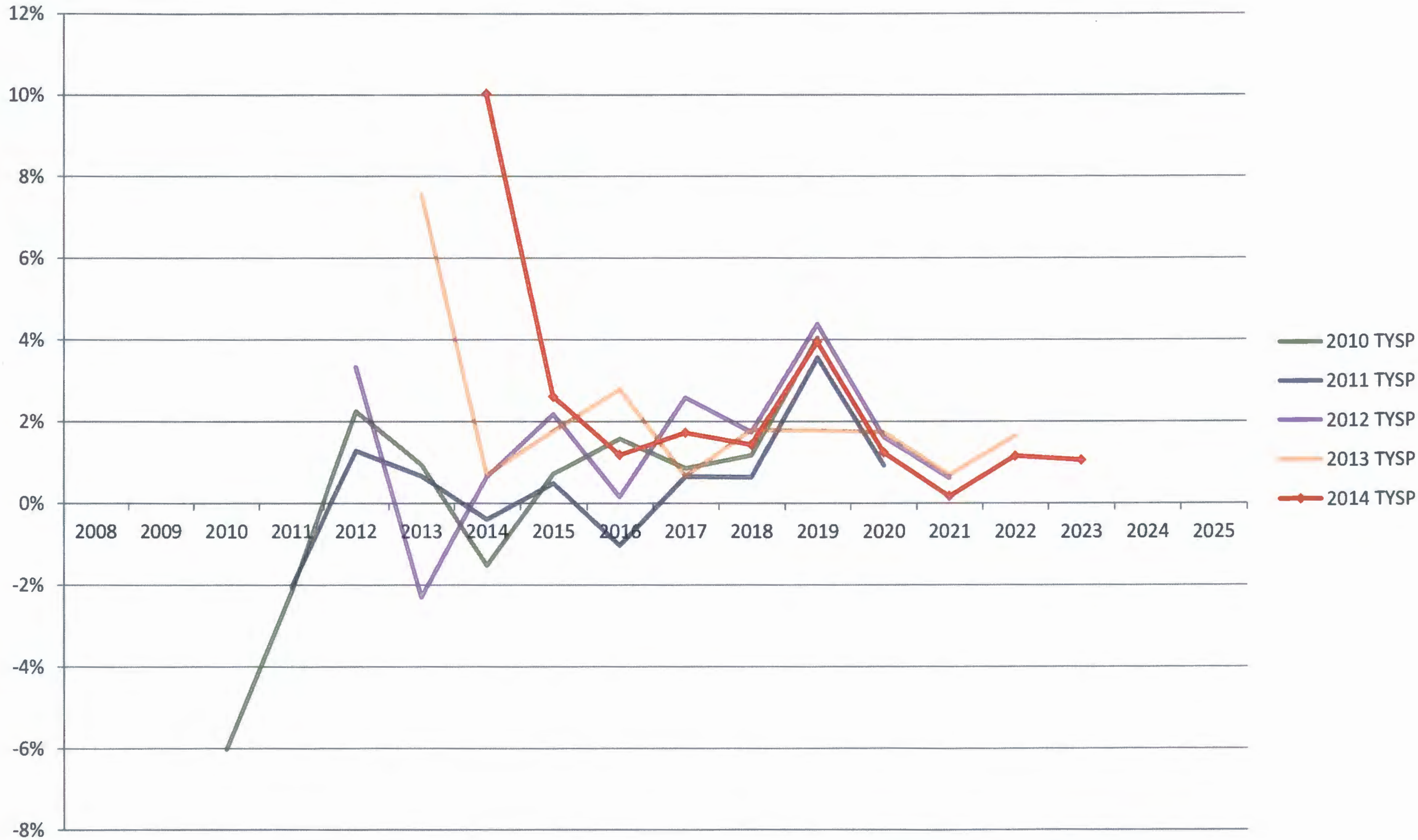
PARTY: Duke Energy Florida

DESCRIPTION: Actual and Forecasted Growth Rates Chart from Ten Year Site Plans 2010, 2011, 2012, 2013, and 2014.

PROFFERED BY: White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate –White Springs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 139
PARTY: PCS
DESCRIPTION: B. Borsch

Forecasted Annual Growth Rates: Summer Net Firm Demand



Source: Calculated from 2010-2014 TYSP Schedule 3.1

EXHIBIT NO. 140

DOCKET NO: 140110-EI & 140111-EI

WITNESS: Borsch

PARTY: Duke Energy Florida

DESCRIPTION: Historic percentage of Summer Net Firm Demand to Average System Demand and adjusted Summer Net Firm Demand Forecast.

PROFFERED BY: White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate –White Springs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 140
PARTY: PCS
DESCRIPTION: B. Borsch

Historic Summer Net Firm Demand as Percentage of Net Energy for Load

	A	B	C	D
Year	Summer Net Firm Demand (MW)	Net Energy for Load (GWh)	Average System Demand (MW)	% Summer Net Firm Demand to Average System Demand
2004	8,224	45,268	5,168	159.15%
2005	9,074	46,878	5,351	169.56%
2006	9,016	46,041	5,256	171.54%
2007	9,735	47,633	5,438	179.03%
2008	9,186	47,658	5,440	168.85%
2009	9,624	44,124	5,037	191.07%
2010	8,929	46,160	5,269	169.45%
2011	8,636	42,490	4,850	178.05%
2012	8,338	41,214	4,705	177.22%
2013	8,008	40,772	4,654	172.05%

Average Summer Net Firm Demand as % of NEL 2009-2013
177.57%

A. 2014 TYSP Schedule 3.1 Col. 10.
B. 2014 TYSP Schedule 3.3 Col. 8.
C. Equal to value in column B times one-thousand divided by 8,760. (B*1,000)/8,760
D. Equal to value in column A divided by value in column C. (A/C)

Forecasted Summer Net Firm Demand as Percentage of Average System Load

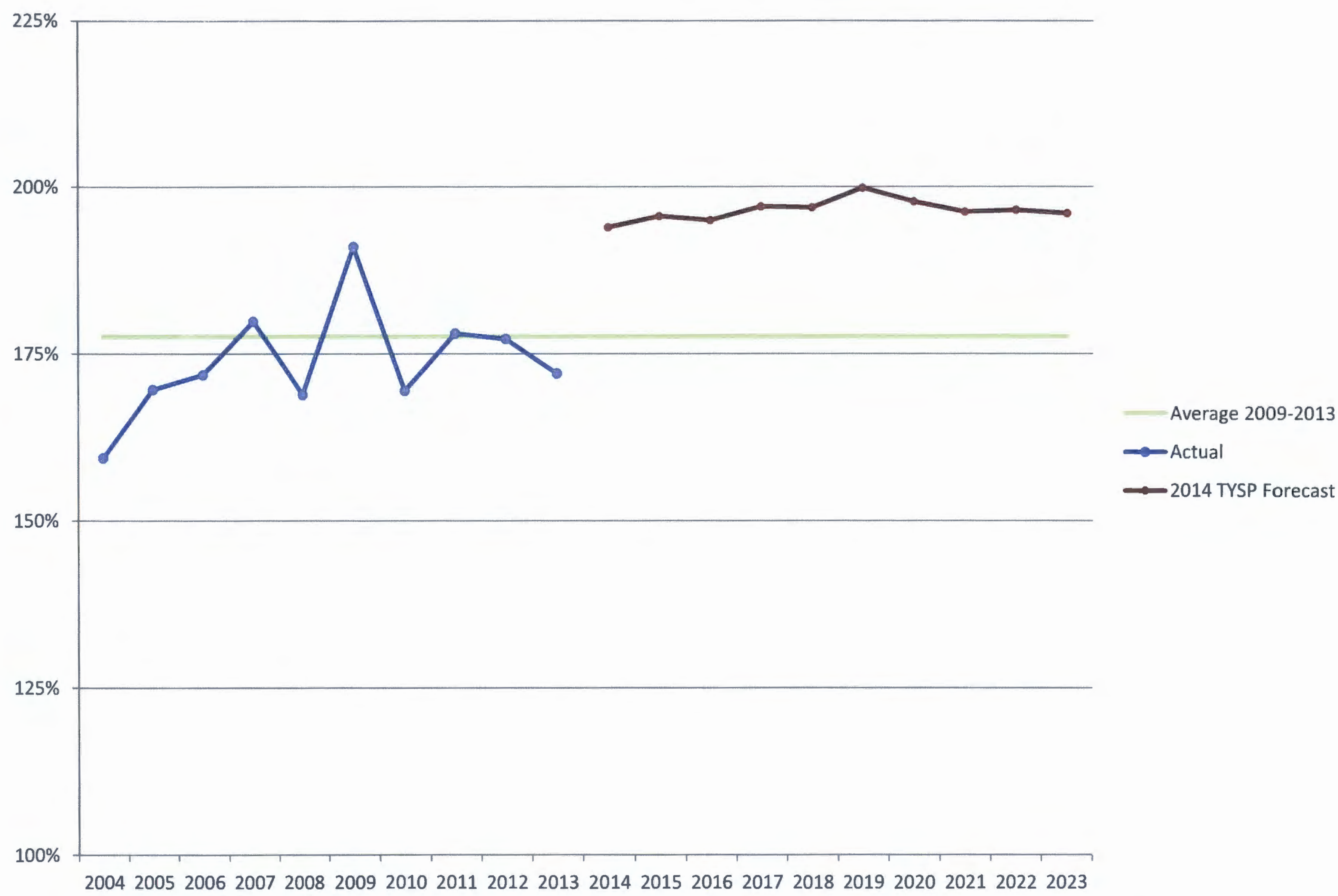
	A	B	C	D
Forecast Year	Summer Net Firm Demand (MW)	Net Energy for Load (GWh)	Average System Demand (MW)	% Summer Net Firm Demand to Average System Demand
2014	8,812	39,801	4,543	193.95%
2015	9,042	40,490	4,622	195.62%
2016	9,149	41,098	4,692	195.01%
2017	9,307	41,375	4,723	197.05%
2018	9,440	41,995	4,794	196.91%
2019	9,813	43,013	4,910	199.85%
2020	9,935	43,998	5,023	197.81%
2021	9,952	44,419	5,071	196.27%
2022	10,067	44,870	5,122	196.54%
2023	10,173	45,459	5,189	196.03%

Average Summer Net Firm Demand as % of NEL 2014-2018
195.71%

Average Summer Net Firm Demand as % of NEL 2014-2023
196.56%

A. 2014 TYSP Schedule 3.1 Col. 10.
B. 2014 TYSP Schedule 3.3 Col. 8.
C. Equal to value in column B times one-thousand divided by 8,760. (B*1,000)/8,760
D. Equal to value in column A divided by value in column C. (A/C)

Summer Net Firm Demand as Percentage of Average System Demand



Source: Calculated from 2014 TYSP Schedules 3.1 and 3.3

Adjusted Forecast Summer Net Firm Demand

	A	B	C
Forecast Year	5-Year Historic % Summer Peak to Average System Demand	Forecasted Average System Demand	Adjusted Summer Net Firm Demand (MW)
2014	177.57%	4,543	8,068
2015	177.57%	4,622	8,207
2016	177.57%	4,692	8,331
2017	177.57%	4,723	8,387
2018	177.57%	4,794	8,513
2019	177.57%	4,910	8,719
2020	177.57%	5,023	8,919
2021	177.57%	5,071	9,004
2022	177.57%	5,122	9,095
2023	177.57%	5,189	9,215

A. % Summer Net Firm Demand to Average System Load 2009-2013.

B. Calculated from 2014 TYSP Schedule 3.3 Col. 8. Forecasted Net Energy for Load, multiplied by 1,000 and divided by 8,760.

C. Value in column A times value in column B. (A*B)

Adjusted Reserve Margin Forecast

	A	B	C	D	E
Forecast Year	Total Capacity Available (MW)	Adjusted Summer Net Firm Demand (MW)	Adjusted Reserve Margin (MW)	Adjusted Reserve Margin % of Peak	2014 TYSP Reserve Margin % of Peak
2014	11,024	8,068	2,956	37%	25%
2015	10,991	8,207	2,784	34%	22%
2016	11,140	8,331	2,809	34%	22%
2017	11,305	8,387	2,918	35%	21%
2018	11,307	8,513	2,794	33%	20%
2019	12,077	8,719	3,358	39%	23%
2020	11,972	8,919	3,053	34%	21%
2021	12,340	9,004	3,336	37%	24%
2022	12,340	9,095	3,245	36%	23%
2023	12,340	9,215	3,125	34%	21%

A. 2014 TYSP Schedule 7.1 Col. 6.
B. Adjusted Summer Net Firm Demand calculated based on average historic % peak demand to average system demand.
C. Adjusted reserve margin calculated by subtracting the value in column B from the value in column A. (A-B)
D. Calculated by dividing the value in column C by the value in column B. (C/B)
E. 2014 TYSP Schedule 7.1 Col. 9.

EXHIBIT NO. 141

DOCKET NO: 140110-EI & 140111-EI

WITNESS: Borsch

PARTY: Duke Energy Florida

DESCRIPTION: Excerpt of Duke Energy Corp. 8-K SEC filing (dated 8/7/14)

PROFFERED BY: White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate –White Springs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-111-EI EXHIBIT: 141
PARTY: PCS
DESCRIPTION: B. Borsch

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

Date of report
(Date of earliest event reported): August 7, 2014

DUKE ENERGY CORPORATION

(Exact Name of Registrant as Specified in Charter)

Delaware	001-32853	20-2777218
(State or Other Jurisdiction of Incorporation)	(Commission File No.)	(IRS Employer Identification No.)

550 South Tryon Street, Charlotte, North Carolina, 28202
(Address of principal executive offices, including zip code)

(704) 594-6200
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Duke Energy Florida
Quarterly Highlights
Supplemental Regulated Utilities Electric Information
June 2014

	Three Months Ended June 30				Six Months Ended June 30			
	2014	2013	% Inc. (Dec.)	% Inc. (Dec.) Weather Normal (2)	2014	2013	% Inc. (Dec.)	% Inc. (Dec.) Weather Normal (2)
GWH Sales (1)								
Residential	4,396	4,491	(2.1%)		8,447	8,235	2.6%	
General Service	3,702	3,694	0.2%		6,950	6,918	0.5%	
Industrial	803	827	(2.9%)		1,604	1,582	1.4%	
Other Energy Sales	6	6	0.0%		12	12	0.0%	
Unbilled Sales	592	379	56.2%		731	413	77.0%	
Total Regular Sales	9,499	9,397	1.1%	0.5%	17,744	17,160	3.4%	1.8%
Special Sales	341	456	(25.2%)		757	709	6.8%	
Total Electric Sales - Duke Energy Florida	9,840	9,853	(0.1%)		18,501	17,869	3.5%	
Average Number of Customers								
Residential	1,498,175	1,476,411	1.5%		1,495,267	1,475,080	1.4%	
General Service	190,979	188,839	1.1%		190,708	188,591	1.1%	
Industrial	2,279	2,357	(3.3%)		2,290	2,359	(2.9%)	
Other Energy Sales	1,556	1,567	(0.7%)		1,556	1,568	(0.8%)	
Total Regular Sales	1,692,989	1,669,174	1.4%		1,689,821	1,667,598	1.3%	
Special Sales	14	15	(6.7%)		15	15	0.0%	
Total Average Number of Customers - Duke Energy Florida	1,693,003	1,669,189	1.4%		1,689,836	1,667,613	1.3%	
Heating and Cooling Degree Days (3)								
Actual								
Heating Degree Days	1	—	n/a		418	338	23.7%	
Cooling Degree Days	1,061	1,041	1.9%		1,205	1,220	(1.2%)	
Variance from Normal								
Heating Degree Days	(90.9%)	(100.0%)	n/a		0.7%	(18.8%)	n/a	
Cooling Degree Days	0.7%	(1.2%)	n/a		(2.1%)	(0.8%)	n/a	

(1) Except as indicated in footnote (2), represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as a single amount and not allocated to the respective retail classes.
(2) Represents weather normal total retail calendar sales (i.e. billed and unbilled sales).
(3) Certain 2013 data has been recast to conform to the 2014 methodology which provides for consistency across all Regulated Utilities' jurisdictions.

EXHIBIT NO. 142

DOCKET NO: 140110

WITNESS:

PARTY:

DESCRIPTION: Duke Avoided Generation Assumptions – Docket No.130200

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 142
PARTY: SACE
DESCRIPTION: B. Borsch

AVOIDABLE GENERATION ASSUMPTIONS

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 1
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2018
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.35
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1105
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	6.09
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P1 - COMBINED CYCLE		unit 2
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2021
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	1,145.43
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	66.82
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.6298
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		28% winter 45% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	4.72
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P2 - COMBINED CYCLE		unit 3
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2024
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	749.45
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	62.85
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.6782
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		28% winter 45% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	5.21
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 4
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2026
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.99
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1347

(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	8.72
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P1 - COMBINED CYCLE		unit 5
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2027
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	1,145.43
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	67.97
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.7303
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		28% winter 45% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	5.81
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 6
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2028
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	64.18
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1415
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	9.38
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P2 - COMBINED CYCLE		unit 7
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2030
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	749.45
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.37
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.7865
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		28% winter 45% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	6.41
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 8
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2036
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	65.00

(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1724
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	12.28
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		**unit 9**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2038
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	65.24
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1811
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	12.93
(12) Avoided Generating Unit Fuel Escalation Rate		

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		**unit 10**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2039
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	65.36
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	0.1857
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	13.44
(12) Avoided Generating Unit Fuel Escalation Rate		

CC2X1 P1 - COMBINED CYCLE		**unit 11**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2041
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$/KW	1,145.43
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	71.41
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	¢/Kwh	1.0319
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		28% winter 45% summer
(11) Avoided Generating Unit Fuel Cost	¢/Kwh	9.02
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

Note: all the fixed cost, variable and fuel costs are nominal dollar value in the first year when unit is in service

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared **Helena T. Guthrie**, who

(✓) is personally known to me, or

(   ) produced ______________________________ as identification and who,

being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 1-26 of SIERRA CLUB'S FIRST SET OF INTERROGATORIES to DEF in Docket No. 130200-EI are true and correct to the best of his/her knowledge, information and belief.

[signature]
Print name: [illegible]

[illegible]
Title

April [illegible]
Date

[signature]
Notary Public
State of Florida

My commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

PROGRESS 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
HISTORY:										
2003	8,881	887	7,994	300	355	169	44	161	75	7,776
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	1618	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	402	9,381	267	326	355	100	278	124	8,333
FORECAST:										
2013	10,462	937	9,525	271	330	382	103	287	124	8,964
2014	10,572	871	9,702	274	335	408	107	298	124	9,026
2015	10,773	873	9,901	277	340	432	110	306	124	9,185
2016	11,066	977	10,089	276	345	452	113	314	124	9,441
2017	11,189	894	10,295	286	368	470	116	320	124	9,504
2018	11,391	894	10,497	288	373	486	120	326	124	9,674
2019	11,607	894	10,713	303	378	501	123	332	124	9,846
2020	11,823	894	10,929	318	383	518	126	337	124	10,017
2021	11,928	794	11,134	326	388	533	129	341	124	10,086
2022	12,121	794	11,327	326	393	548	133	345	124	10,252

Historical Values (2003 - 2012):
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 (2013 - 2022):
Cols. (2) - (4) = forecasted peak without load control, 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).

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Review Of The
2013 Ten-Year Site Plans
For Florida's Electric Utilities

Florida Public Service Commission

Tallahassee, FL
October 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-EI EXHIBIT: 144
PARTY: SACE
DESCRIPTION: B. Borsch

Load and Energy Forecast

Accuracy of Energy Forecasts

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of past retail energy sales forecasts. The review compared actual retail energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2012 energy sales were compared to the projected 2012 value from forecasts made in 2009, 2008, and 2007. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy using a five year rolling average. For example, the 2012 error rate looks at the difference between actual retail energy sales for 2012 through 2008, drawing upon projections made between 2009 through 2003. An average error with a negative value indicates a tendency to under-forecast, while a positive value represents an over-forecasting of retail energy sales. Absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under/over-forecast.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts

TYSP Year	Five Year Period	Forecast Error (%)	
		Average	Absolute Average
2009	2008 - 2004	1.79%	3.56%
2010	2009 - 2005	5.01%	5.71%
2011	2010 - 2006	8.31%	8.31%
2012	2011 - 2007	11.91%	11.91%
2013	2012 - 2008	15.10%	15.10%

Source: 2004 - 2013 TYSPs

Table 5 above illustrates the historical forecast error for the combined 2013 through 2009 TYSPs. These correspond to actual data from 2012 through 2008. Overall, a pattern of increasing error in retail sales forecasts is shown, with error over 10 percent based in 2011 and 2012. The high error rate, which has increased each year for the past five years, seems to be associated with the unexpected impacts of the recession on retail energy sales in Florida, both from reduction in the state's growth rate, but also from decreased usage per capita. As the five year rolling average progresses and includes more years post-recession, the error values should subside.

Table 6 below provides a more detailed data set used to calculate the average error rating, showing forecasts made between one and six years prior. A significant increase in error is evident in 2008 and beyond, with forecasts made post 2009 improving in accuracy and approaching historic levels of error. As this analysis moves forward and begins to use forecasts developed after the beginning of the recession, the error rate should fall back to typical levels.

Load and Energy Forecast

Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis

Year	Years Prior						Average Error	Absolute Average Error
	6	5	4	3	2	1		
2004	-	-4.96%	-3.06%	0.31%	-0.47%	1.05%	**-2.57%**	**2.78%**
2005	-5.79%	-4.00%	-0.66%	-0.60%	0.75%	0.93%	**-1.75%**	**1.75%**
2006	-3.24%	0.02%	1.08%	2.35%	2.48%	2.42%	**1.15%**	**1.15%**
2007	0.61%	2.31%	3.54%	3.63%	4.25%	3.09%	**3.16%**	**3.16%**
2008	7.02%	8.40%	8.55%	9.97%	9.24%	8.34%	**8.97%**	**8.97%**
2009	11.97%	12.17%	14.50%	13.93%	12.70%	10.19%	**13.53%**	**13.53%**
2010	12.94%	15.58%	14.89%	13.70%	10.56%	-0.73%	**14.72%**	**14.72%**
2011	21.39%	20.63%	19.92%	16.86%	3.65%	-0.06%	**19.14%**	**19.14%**
2012	26.30%	25.97%	23.03%	8.47%	3.90%	3.70%	**19.15%**	**19.15%**

Source: 2004 - 2013 TYSPs

As indicated by this high error rate, utilities projected increased need for energy that has not materialized due to the recession. The TYSP utilities have responded to changing circumstances by delaying or cancelling new generation and taking opportunities to modernize existing plants, as discussed in previous annual reviews of the TYSPs.

EXHIBIT NO. 145

DOCKET NO: 140110 -140111

WITNESS: Ben Borsch

PARTY: FIPUG

DESCRIPTION: Current Draft Air Permit

PROFFERED BY:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140110-111-EI EXHIBIT: 145
PARTY: FIPUG
DESCRIPTION: B. Borsch

Duke Energy Florida, Inc. (DEF)
Crystal River Power Plant

Facility ID No. 0170004
Citrus County

Title V Air Operation Permit Renewal

Permit No. 0170004-046-AV

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance

2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000
Fax: (850) 717-9097

Compliance Authority:

State of Florida
Department of Environmental Protection
Southwest District Office

13051 North Telecom Parkway
Temple Terrace, FL 33637-0926

Telephone: 813/632-7600
Fax: 813/632-7668

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FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

BOB MARTINEZ CENTER
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

RICK SCOTT
GOVERNOR

CARLOS LOPEZ-CANTERA
LT. GOVERNOR

HERSCHEL T. VINYARD
JR.

PERMITTEE:

Duke Energy Florida, Inc.
299 First Avenue North
Mail Code CN77
St. Petersburg, Florida 33701

Permit No. 0170004-046-AV
Crystal River Power Plant
Facility ID No. 0170004
Title V Air Operation Permit Renewal

The purpose of this permit is to renew the Title V air operation permit for the facility.

The existing Crystal River Power Plant is located in Citrus County at 15760 West Power Line Street, Crystal River, Florida. UTM Coordinates are: Zone 17, 334.3 km East and 3204.5 km North. Latitude is: 28° 57' 34" North and Longitude is: 82° 42' 1" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Effective Date: January 1, 2015
Renewal Application Due Date: May 20, 2019
Expiration Date: December 31, 2019

Executed in Tallahassee, Florida.

(Draft/Proposed)

for: Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

JFK/dlr/tbc

Subsection A. Facility Description.

This facility consists of: four coal-fired fossil fuel steam generating (FFSG) units with electrostatic precipitators; two natural draft cooling towers for FFSG Units 4 and 5; helper mechanical cooling towers for FFSG Units 1 and 2 ~~and nuclear Unit 3~~; coal, fly ash, and bottom ash handling facilities; limestone and gypsum material handling activities; hydrated lime storage and transfer system for Units 4 and 5; and, ~~relocatable diesel-fired~~ various fire pumps and generators. ~~The facility is also authorized to operate a portable concrete batch plant (EU 033), as needed for on-site maintenance.~~ ~~Nuclear Unit 3 is not considered part of this permit, although certain emissions units associated with Unit 3 are included in this permit.~~ The facility continuously operates low-NO_X burners, selective catalytic reduction systems (SCR), flue gas desulfurization systems (FGD) which includes limestone and gypsum material handling activities and acid mist mitigation (AMM) systems for existing Units 4 and 5, as authorized by permits No. 0170004-023-AC (PSD-FL-383C) and 0170004-037-AC (PSD-FL-383E). In conjunction with the new control equipment, Units 4 and 5 are now also authorized to burn a blend of bituminous/sub-bituminous coal.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

E.U. No.	Brief Description
Regulated Emission Units	
001	FFSG, Unit 1
002	FFSG, Unit 2
003	FFSG, Unit 5
004	FFSG, Unit 4
006	Fly ash transfer (Source 1) from FFSG Unit 1
008	Fly ash storage silo (Source 3) for FFSG Units 1 and 2
009	Fly ash transfer (Source 4) from FFSG Unit 2
010	Fly ash transfer (Source 5) from FFSG Unit 2
~~012~~	~~Relocatable diesel generators~~
013	Cooling towers for FFSG Units 1~~,~~ and 2~~, and 3~~
014	Bottom ash storage silo for FFSG Units 1 and 2
016	Material handling activities for coal-fired steam units
~~020~~	~~Portable Cooling Towers for FFSG Units 1 and 2~~
~~028~~	~~3500 kW diesel generator associated with Unit 3~~
023	Limestone and Gypsum Material Handling Activities
029	Diesel fire pump, south yard
032	Hydrated Lime Storage and Transfer System for Units 4 and 5
033	Portable Concrete Batch Plant
034	Diesel Emergency Fire Pump
035	Emergency Diesel Generator for Security Building and System (Backup)
036	260 kW Emergency Diesel Generator at Unit 3 Technical Support Center
037	Unit 3 Diesel Generator Air Compressor
038	Fire Pump House Emergency Diesel Generator Unit for North Plant
039	175 kW Emergency Diesel Generator for Site Administration Building
Unregulated Emissions Units and/or Activities	
017	Fuel and lube oil tanks and vents
018	Sewage treatment, water treatment, lime storage
019	3500 kW diesel generator associated with Unit 3

030	Emergency generator (meteorological weather station)

Subsection C. Applicable Regulations.

Based on the Title V air operation permit renewal application received May 20, 2014, this facility is a major source of hazardous air pollutants (HAP). The existing facility is a PSD major source of air pollutants in accordance with Rule 62-212.400, F.A.C. Summary of applicable regulations is shown in the following table.

Regulation	EU Nos.
40 CFR 60, Subpart A, NSPS General Provisions	003, 004, 016
40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	003, 004
40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	029
~~40 CFR 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines~~	~~030~~
40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants	023
40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	~~028,~~ 029, 030, 034, 035, 036, 037, 038, 039
40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil- Fired Electric Utility Steam Generation Units	001, 002, 003, 004
40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants.	016
40 CFR 75 Acid Rain Monitoring Provisions	001, 002, 003, 004
Rule 62-296.340 (BART), F.A.C.	001, 002
Rule 62-296.405, F.A.C.	001, 002
Rule 62-210.370, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016~~, 020~~
Rule 62-210.700, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016~~, 020, 033~~
Rule 62-213.410, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016~~, 020, 033~~
Rule 62-213.440, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016~~, 020, 033~~
Rule 62-297.310, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016~~, 020~~, 032, ~~033~~

The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section **VI**, Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. Not federally Enforceable. Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.
d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1), F.A.C.]

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

FW5. Unconfined Particulate Matter. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. Maintenance of paved areas as needed.
b. Regular mowing of grass and care of vegetation.
c. Limiting access to plant property by unnecessary vehicles.
d. To the extent practicable, the hydrated lime handling and storage operations shall be enclosed and confined to prevent fugitive dust emissions from the unloading, storage and handling of hydrated lime.
e. Fabric filters shall be properly maintained on the hydrated lime storage silos to provide assurance that visible emissions exhausted during the filling of the silos and operation of the handling and storage equipment remains below the design emission rate of 5% opacity.

[Rule 62-296.320(4)(c), F.A.C. ; Permit No. 0170004-037-AC (PSD-FL-383F); and, proposed by applicant in Title V air operation permit renewal application received May 20, 2014.]

Annual Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements for additional details.

FW6. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each

Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070.** Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

{Permitting Note: Resources to help you complete your AOR are available on the electronic AOR (EAOR) website at: http://www.dep.state.fl.us/air/emission/eaor. If you have questions or need assistance after reviewing the information posted on the EAOR website, please contact the Department by phone at (850) 717-9000 or email at eaor@dep.state.fl.us.}

{Permitting Note: The Title V Annual Emissions Fee form (DEP Form No. 62-213.900(1)) has been repealed. ***A separate Annual Emissions Fee form is no longer required to be submitted by March 1st each year.}***

FW7. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

FW8. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. (See paragraph e., below.)
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Division of Emergency Management, as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the Division of Emergency Management on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.
d. Any required written reports, notifications, certifications, and data required to be sent to the Division of Emergency Management, should be sent to: Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9970, Fax: (850) 488-1739.
e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.
f. Any required reports to be sent to the National Response Center, should be sent to: National Response Center, EPA Office of Solid Waste and Emergency Response, USEPA (5305 W), 401 M Street SW, Washington, D.C. 20460, Telephone: (800) 424-8802.
g. Send the required annual registration fee using approved forms made payable to: Cashier, Division of Emergency Management, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

{Permitting Note: There is currently no RMP required for this facility.}

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
001	FFSG, Unit 1
002	FFSG, Unit 2

Emissions unit 001 (EU001) is a pulverized coal, dry bottom, tangentially-fired boiler. It is rated at 440.5 megawatts (MW). Emissions are exhausted through a 499 feet stack with a 15 feet exit diameter, 291° F exit temperature and 1,407,923 acfm actual volumetric flow rate.

Emissions unit 002 (EU002) is a pulverized coal, dry bottom, tangentially-fired boiler. It is rated at 523.8 MW. Emissions are exhausted through a 502 feet stack with a 16 feet exit diameter, 300° F exit temperature and 1,931,324 acfm actual volumetric flow rate.

Emissions from both EU001 and EU002 are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc.

{Permitting Notes: These emissions units are regulated under Acid Rain, Phase I and II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input, Rule 62-296.340 (BART), F.A.C., and Power Plant Siting Certification PA 77-09 conditions. The pollutants' emissions limits in Rule 62-296.405, F.A.C., have been changed through Permit Nos. 0170004-003-AC, 0170004-006-AC, 0170004-017-AC, 0170004-036-AC and 0170004-038, PSD-FL-007, and PA 77-09. Fossil fuel fired steam generator Unit 1 began commercial operation in 1966. Fossil fuel fired steam generator Unit 2 began commercial operation in 1969.}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	MMBtu/hr Heat Input	Fuel Type
001	3,750	Bituminous Coal~~; or Bituminous Coal and Bituminous Coal Briquette Mixture~~
002	4,795	Bituminous Coal~~; or Bituminous Coal and Bituminous Coal Briquette Mixture~~

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, Permit Nos. 0170004-003-AC and 0170004-006-AC; 0170004-045-AC, Specific Condition 2.]

{Permitting Note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.2. Cessation of Coal Combustion. Units 1 and 2 shall cease to be operated as coal-fired units by December 31, 2020. [Permit Nos. 0170004-036-AC, Specific Condition A.1. and 0170004-038-AC, Specific Condition A.2.]

A.3. Methods of Operation.

a. *Fuels.* The fuels that are allowed to be burned in these units are:
   (1) Bituminous coal, and
   ~~(2) Bituminous coal and bituminous coal briquette mixture,~~
   (3) Distillate fuel oil for startup.~~, and~~
   ~~(4) Used oil in accordance with the specific conditions in Subsection J.~~